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Oil Recovery by Surfactant Flooding; Sensitivity Analysis to Technical Parameters and Economic Analysis

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OIL RECOVERY BY SURFACTANT FLOODING; SENSITIVITY ANALYSIS TO TECHNICAL PARAMETERS AND ECONOMIC ANALYSIS

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Declaration of Original Work

I, Hadel Mohsen Moustafa, the undersigned, a graduate student at the United Arab Emirates University (UAEU), and the author of this thesis entitled "*Oil Recovery by Surfactant Flooding; Sensitivity analysis to technical parameters and economic analysis*", hereby, solemnly declare that this thesis is my own original research work that has been done and prepared by me under the supervision of Dr.Gamal Alusta, in the College of Engineering at UAEU. This work has not previously been presented or published, or formed the basis for the award of any academic degree, diploma or a similar title at this or any other university. Any materials borrowed from other sources (whether published or unpublished) and relied upon or included in my thesis have been properly cited and acknowledged in accordance with appropriate academic conventions. I further declare that there is no potential conflict of interest with respect to the research, data collection, authorship, presentation and/or publication of this thesis.

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Abstract

Various enhanced oil recovery methods including miscible gas injection, chemical, thermal and other methods are applied at the third phase of production after the primary and secondary recovery have been exhausted. Surfactant flooding is one of the chemical methods that is capable of recovering more oil by decreasing the IFT and/or wettability alteration.

This piece of work aims to asses and select the development options using surfactant process that maximize oil recovery for a synthetic reservoir model by optimizing technical and economic analysis.

Reservoir simulation study using ECLIPSE 100 was used to study the different development options of surfactant flooding applied and compare them to waterflooding. The development options include continuous surfactant injection, secondary surfactant flooding, and tertiary surfactant flooding. Through the study, the effect of injection rate, surfactant concentration and slug size were investigated by setting up a range of sensitivities.

Results of the study reveal a general trend of increased oil recovery with the implementation of surfactant flooding over waterflooding in the range of 0.3 - 7%. In the continuous surfactant injection, the highest field oil efficiency of about 52% was achieved using surfactant concentration of 30 lb/stb at 2000 stb/d. The optimum development process from the technical and economic point of view is injecting 0.25 PV of surfactant as a tertiary recovery process using 25 lb/stb of surfactant and 2000 stb/d as an injection rate. The selected system yields an oil recovery of 48.91%.

The outcomes of this project is expected to assist the oil industry in planning surfactant flooding for heterogeneous reservoirs; which is the case of most reservoirs in UAE.

Keywords: Enhanced oil recovery, surfactant flooding, continuous surfactant injection, field oil efficiency, tertiary recovery.

Title and Abstract (in Arabic)

انتاج النفط باستخدام حقن محلول كيميائي (خافض التوتر السطحي)؛ دراسة تحليلية للعوامل التشغيلية و تحليل اقتصادي

الملخص

العديد من التقنيات المتقدمة لاستخراج النفط بما في ذلك حقن الغاز المخلوط، الطرق الكيميائية، و الطرق الحرارية و غيرها يتم تطبيقهم في المرحلة الثالثة من الإنتاج بعد استنفاذ الطرق الأولية و الثانوية. الغمر بخافض التوتر السطحي، هو إحدى الطرق الكيميائية المستخدمة لاستعادة المزيد من النفط. يتم ذلك عن طريق خفض التنقل في النظام؛ و من خلال أو عن طريق تغير التبلل.

الهدف من المشروع هو تقويم و تحديد خيارات التطوير باستخدام تقنية خفض التوتر السطحي لزيادة إنتاج النفط لنموذج اصطناعي للخزان حيث يتم بذلك تحسين المعايير الفنية بدقة و تطبيق الدراسات الاقتصادية.

لإجراء دراسة المحاكاة للخزان، تم استخدام ECLIPSE 100 لدراسة الخيارات التطويرية للغمر بخافض التوتر السطحي و مقارنتها بالغمر بالماء . الخيارات التطويرية تشمل حقن خافض التوتر السطحي باستمرار، الغمر الثانوي لخافض التوتر السطحي، الغمر الثالوثي لخافض التوتر السطحي. خلال الدراسة، تأثير معدل الحقن، تركيز خافض الوتر السطحي، و حجم الجرعة تم تحليلهم عن طريق وضع العديد من الخيارات التحليلية.

كشفت نتائج الدراسة بشكل عام على تحسين معدلات استخراج النفط باستخدام طريقة غمر خافض التوتر السطحي على الحقن بالمياه بنسبة تتراوح ما بين0.3 - 7%. في حقن خافض التوتر السطحي المستمر، تم الحصول على أعلى كفاءة للنفط بنسبة تزيد عن 52%

باستخدام خافض توتر سطحي تركيزه 30 رطل\برميل سطحي عند ضخ 2000 برميل سطحي يوميا . العملية التطويرية المثلى من المنظور الاقتصادي و الفني هي حقن 0.25 من الحجم المسامي كمرحلة استخراجية ثالوثية باستخدام 25 رطل\ برميل سطحي من خافض التوتر السطحي عند ضخ 2000 برميل يوميا لنظام المختار في هذه الحالة يعطي إنتاجية بنسبة 48.91%.

نتائج هذه الدراسة ينبغي أن تساعد القطاع الصناعي للنفط في التخطيط لعمليات غمر خافض التوتر السطحي في الخزانات الغير متجانسة؛ و هي الخزانات الاكثر شيوعا في دولة الامارات المتحدة

مفاهيم البحث الرئيسية: الاستخراج المعزز للنفط، غمر خافض التوتر السطحي، الحقن المستمر لخافض التوتر السطحي، الاستخراج الثالوثي ، الإنتاج الكلي للنفط.

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Special thanks go to my parents, brothers, sisters and husband who helped me along the way.

Dedication

To my beloved parents and my dear husband

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List of Abbreviations

B_o	Oil Formation Volume Factor
EOR	Enhanced Oil Recovery
FOE	Field Oil Efficiency (%)
FOPT	Field Oil Production Total (stb)
FPR	Field Pressure (psia)
FTPTSUR	Field Surfactant Injection Total (lb)
FTITSUR	Field Surfactant Production Total (lb)
FWCT	Field Water Cut (dimensionless)
FWIT	Field Water Injection Total (stb)
FWPT	Field Water Production Total (stb)
IFT	Interfacial Tension
IOIP	Initial Oil In Place
IOR	Improved Oil Recovery
k	Permeability (md)
k_{ro}	Relative permeability to oil (md)
k_{rw}	Relative permeability to water (md)
N_c	Capillary number
P_b	Bubble point pressure (psia)
P_{cow}	Oil water capillary pressure (psia)
PV	Pore Volume
PVT	Pressure-Volume-Temperature
S_w	Water saturation (fraction)
μ_o	Oil viscosity (cp)
μ_w	Water viscosity (cp)

ν	Velocity of the displacing fluid
σ	Oil-water interfacial tension
θ	Contact angle between the oil-water interface

Chapter 1: Introduction

1.1 Overview

Oil recovery processes have been conventionally subdivided into three stages: primary, secondary, and tertiary. Primary production, which is the initial production stage, results from the displacement of oil by the natural energy that exists in the reservoir. Secondary recovery is usually implemented after primary production declines. Waterflooding and gas injection are among the traditional secondary recovery processes (Green et al., 1998). Tertiary recovery is any technique applied after secondary recovery (Lake et al., 1986). Enhanced oil recovery (EOR) encompasses all methods that use external energy resources and/or materials to recover oil that cannot be produced economically by conventional techniques. EOR includes the following:

- Chemical methods: polymer, surfactant, micellar polymer and caustic alkaline.
- Miscible methods: hydrocarbon gas, carbon dioxide and nitrogen.
- Thermal methods: steam flooding, steam stimulation and in-situ combustion (Satter et al., 2008).

Most enhanced oil recovery methods can be categorized as secondary or tertiary depending at which stage of the reservoir producing life they are applied (Robertson et al., 1989).The optimum application of each method depends on the reservoir characteristics including oil type (Donaldson et al., 1985). In the last decade, improved oil recovery (IOR) has been used interchangeably with EOR. Although, there is no formal definition, IOR refers to any process that improves oil recovery

(Stosur et al. , 2003). Therefore, IOR includes other practices such as waterflooding, pressure maintenance, infill drilling and horizontal wells (Lake et al., 1986).

1.2 Statement of the Problem

Primary depletion and secondary recovery processes typically recover about one third of the original oil-in-place. Thus, about two trillion barrels of conventional oil and five trillion barrels of heavy oil remain in reservoirs after these methods have been exhausted. The low oil recoveries from conventional methods are the result of poor macroscopic sweep efficiencies that are attributed to the lack of mobility control and inefficient microscopic displacement caused by capillary trapping of oil mainly due to wettability and interfacial forces (Romsted, 2014). Thus, in recent years, the field of enhanced oil recovery has become more popular due to a combination of the world's rising energy consumption, stagnant oil production, and low recoveries by conventional methods. EOR processes offer prospects for ultimately producing 30-60% or more of the reservoir IOIP (ARI, 2006). Surfactant flooding has the potential to improve recovery by reducing IFT and/or wettability alteration (Green et al.,1998).

1.3 Relevant Literature

1.3.1 Introduction to Surfactants

Surfactants, also called surface-active agents, are chemical substances that are adsorbed onto surfaces or interfaces of a system when present at low concentrations (Green et al., 1998). They have a distinctive molecular configuration containing a structural group that has very little affinity for the solvent, called a lipophobic group, together with a group that has strong affinity for the solvent, known as the lipophilic group (Rosen et al,, 2004). The lipophilic portion usually contains a long hydrocarbon chain which may be linear or branched. This lipophilic-lipophobic structure is named as amphipathic structure (Donaldson et al., 1989). The lipophilic group is usually called the “tail” and the lipophobic the “head” of the molecule (Green et al.,1998). The surface properties of such a compound are governed by the balance between its lipophilic and lipophobic features. A surfactant is called water soluble when it contains a hydrocarbon chain which could be linear or branched with less than 12 carbon atoms since the polar head groups drag the whole molecule in water. Conversely, when the chain length is greater than 14 carbon atoms, the compounds are named water-insoluble surfactants since they do not dissolve in water because of the long hydrocarbon chains (Donaldson et al., 1989).

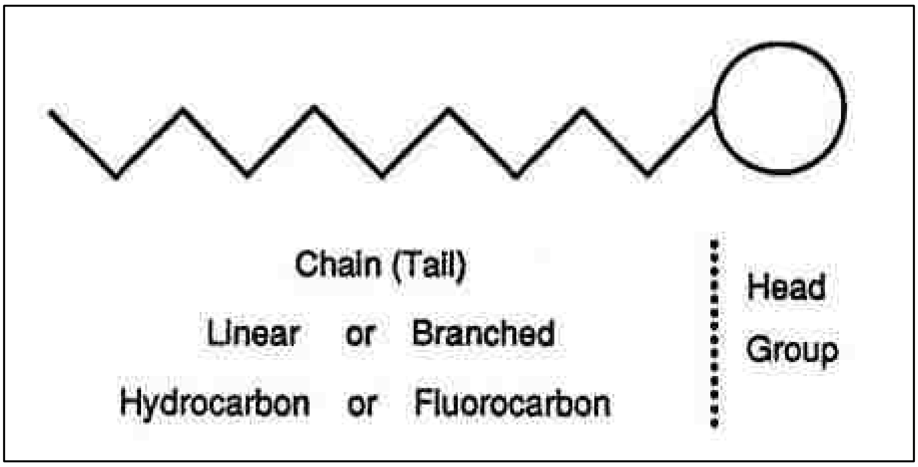

Figure 1-1: Surface-active molecular structure (Green et al., 1998)

1.3.2 Classification of Surfactants

Most commonly, surfactants are classified based on the ionic nature of the head group as anionic, cationic, nonionic, zwitterionic. The head group in anionic surfactant bears a negative charge in aqueous solutions as in sodium dodecyl sulfate

($C_{12}H_{25}SO_4^-Na^+$), whereas the head group in cationic surfactant bears a positive charge in aqueous solutions as in dodecyltrimethylammonium bromide ($C_{12}H_{25}N^+Me_3Br^-$). Non-ionic surfactant does not ionize in aqueous solutions as in dodecylhexaoxyethylene glycol monoether ($C_{12}H_{25}[OCH_2CH_2]_6OH$), whereas Zwitterionic bears both positive and negative charges in the surface-active portion as in dimethylsulfonioacetate $(CH_3)_2S^+[CH_2]CO_2^-$) (Green and Willhite,1998).

1.3.3 Applications of Surfactants

Surfactants represent one of the major and most versatile products used in the chemical industry (Rosen et al., 2004). There are many applications for the products that are used daily (e.g. soaps, detergents, shampoos, cosmetics, pharmaceuticals, foods, and etc.) and in industry (e.g. oilfield chemicals, textile finishing and processing ,emulsions, paint and coatings, pulp and paper, etc.) (Myers,2006).

1.3.4 Surfactants in the Petroleum Industry

Surfactants are used throughout the petroleum industry. They are important in drilling, cement slurries, acidization, fracturing ,corrosion inhibition, demulsification, cleaning, transportation, waterflooding, steam, foam and chemical flooding and environment protection (Bhardwaj et al., 1993).

1.3.4.1 Use of Surfactants in Oil Recovery

The use of surfactants for improving the oil recovery started in late 1920’s and early 1930’s (Donaldson et al., 1985).Anionics and nonionics surfactants have been used in EOR processes. Anionic surfactants have been the most widely used in oil recovery processes since they are relatively stable, have good surfactant properties, exhibit relatively low adsorption on reservoir rock, and can be produced in an economical manner. Among the numerous anionic surfactants, sulfonates have been commonly used in EOR processes during the past 50 years. These include: petroleum sulfonates, synthetic sulfonates and ethoxylates sulfonates (Donaldson et al., 1989). Nonionic surfactants have been used mainly as surfactants to enhance the behavior of surfactant systems. They are much more tolerant of high salinity brine compared to anionics but their surface active properties are not as good as anionics. Cationics are not usually used because they strongly adsorb on reservoir rocks (Green et al., 1998).

1.3.4.2 Surfactant Flooding

Surfactant flooding is an EOR process in which surfactant solution is injected to sweep the reservoir. The presence of surfactant lowers the interfacial tension between the oil and water phases and also changes the reservoir rock wettability to improve oil recovery. It has appeared in the literature under many names such as low-tension flooding detergent flooding and chemical flooding (Romsted, 2014) .Surfactant flooding creates microemulsion solutions, which may consist of different combinations of surfactants, co-surfactants, hydrocarbons, water and electrolytes (Green et al., 1998). A typical surfactant flood is shown below:

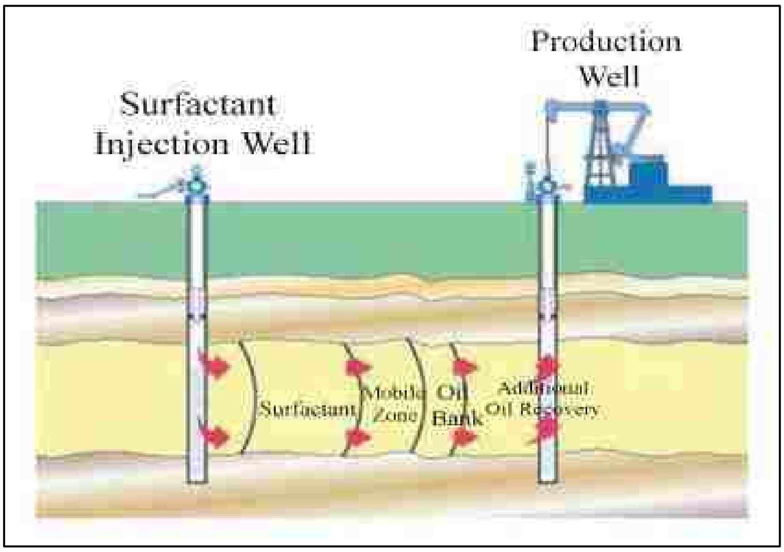

Figure 1-2: Surfactant flooding process (Emgwalu, 2009)

Generally, there are three types of surfactant flooding for EOR (Rosen et al., 2005) as shown in the following table :

Table 1-1: Types of surfactant flooding

Type of surfactant flooding	Technique	Note
Microemulsion flooding	Microemulsions are formed by injecting surfactants, co-surfactant, alcohol, and brine to obtain ultralow IFT.	It can be designed to perform well in high temperature or salinity or low permeable areas where polymer and/or alkali cannot succeed.
Micelle/polymer flooding	A micelle slug usually containing surfactant, co-surfactant, alcohol, brine and oil is injected into the reservoir.	Displacement efficiency close to 100% (laboratory measurement).
Alkaline/surfactant/polymer flooding	The addition of alkaline chemicals lowers the IFT at considerably low surfactant concentrations.	Lower concentration of surfactants is involved in this process in order to reduce the cost of chemicals.

Surfactant flooding can be conducted as a tertiary displacement near the end of waterflood or as a secondary flood (Green and Willhite,1998).

The favorable characteristics for Surfactant Flooding include :

- High permeability and porosity.
- High remaining oil saturation (>25%).
- Light oil less than 50 cp--but recent trend is to apply to viscous oils up to 200 cp or even higher viscosity.
- Short project life due to favorable combination of small well spacing and/or high injectivity.
- Onshore.
- Good geological continuity.
- Good source of high quality water.
- Reservoir temperatures less than 300 ºF.

1.3.4.2.1 Main Aspects of Surfactant Flooding

I. Reservoir temperature

II. Timing

III. Capillary forces and capillary number

At the end of waterflooding, the remaining oil is believed to be present as immobile globules distributed through the rock pores in petroleum reservoirs. The two main forces acting on these immobile globules are capillary forces and viscous forces. The capillary number is defined as the ratio of viscous forces to capillary forces and is represented as:

$$N_{ca} = v\mu / \sigma \cos\theta \tag{1.1}$$

where ν and μ are velocity and viscosity of the displacing fluid, respectively, σ is the oil-water interfacial tension and θ is the contact angle between the oil-water interface and the rock surface measured through the denser phase, which is water in this case (Donnez , 2012).

At the end of waterflooding, the capillary number ranges from 10^{-6} to 10^{-7}. The oil displacement efficiency increases as the capillary number increases. The capillary number can be increased by increasing the aqueous phase viscosity (μ_w) and flow rate or by decreasing the interfacial tension between oil and water, which generally ranges from 20 to 30 dyne/cm. By injecting an appropriate surfactant, the interfacial tension can be lowered to 10^{-3} or 10^{-4} dyne/cm (Donaldson et al., 1989).

IV. Interfacial tension

It is well accepted that oil recovery efficiency can be improved by obtaining ultra-low interfacial tension between oil and water by adsorption at the interface. The flow of trapped oil droplets or ganglia through the narrow necks of pores is illustrated schematically in Figure 1-3 (Donaldson et al., 1989).

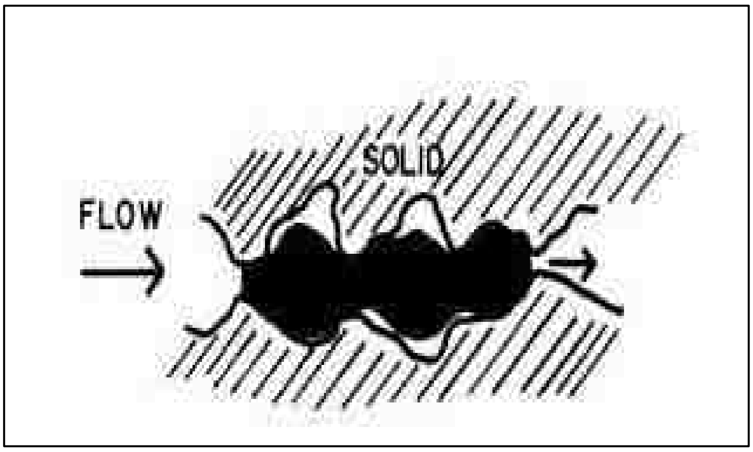

Figure 1-3: The effect of IFT on the movement of oil ganglia through the narrow necks of pores (Donaldson et al., 1989)

An ultra-low interfacial tension (often less than 10^{-3} dyne/cm) between oil and water phases is required for easy the flow of trapped oil drops since it reduces the deformation work needed for oil ganglia to move through the narrow necks of pore channels (Donaldson et al., 1989). Foster (1973) and Hill, Reisberg and Stegemeier (1973) observed that relatively small concentrations of petroleum sulfonates can produce such low interfacial tension between oil and water. Researchers found that the IFT of an oil–water–surfactant system is a function of salinity, oil composition, surfactant type and concentration, cosurfactant, electrolytes, temperature, and the phase behavior of the system (Adkins et al., 2012).

- Influence of salinity on IFT

Winsor (1954) recognized three types of phase equilibria in microemulsion phase as type I, type II, and type III. Healy and Reed (1974) explained how the Winsor-type behavior describes the change in phase behavior, solubilization of oil and water and IFT as a function of salinity for anionic surfactants. The oil–water–surfactant system is strongly affected by the water salinity. This phase behavior is represented by a ternary diagram as shown in the Figure 1-4:

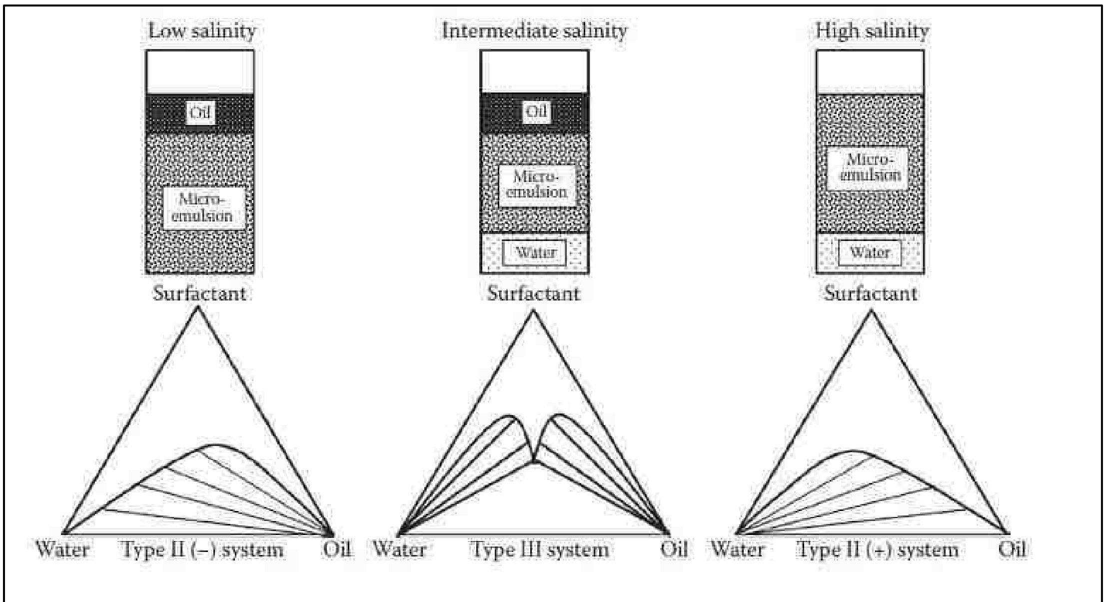

Figure 1-4: Three types of microemulsions and the effect of salinity on phase behavior (Healy and Reed, 1974)

The surfactant flood exhibit good aqueous phase solubility and poor oleic phase solubility in case of low brine salinities, thus forming type I phase behavior. In type I system, an oil-in-water microemulsion is formed, and the surfactant remains in the aqueous phase (Schramm et al., 2000). This system is referred to as the lower phase microemulsion or type II (-) system, where II means no more than two phases can form and (-) means that the tie-lines have negative slope. This phase behavior is not favorable to achieve ultralow IFT. A water-in-oil microemulsion with an excess oil phase is defined as the upper phase microemulsion or type II (+). This behavior leads to the retention of surfactants in the oil phase and is not favored in EOR. In a type III microemulsion, the surfactant forms a microemulsion in a separate phase between the oil and aqueous phases. This phase forms a continuous layer containing surfactant, water and dissolved hydrocarbons. Usually, type III provides low IFT especially when equal volumes of water and oil are solubilized in the microemulsion. This condition is defined as optimal salinity, which exhibits the lowest IFT between the water and the oil. In addition, optimal salinity can be expressed as the midpoint salinity where IFT between microemulsion and water and that between microemulsion and oil are more or less the same. Type III system is desirable for EOR processes (Aoudia et al., 1995).

A. Influence of surfactant structure on IFT

Bourrel and Schechter (1988) has established a clear relationship between surfactant structure and fluid properties associated with EOR performance. The surfactant structure determines its solubility in either water or oil. Increasing the effect of the nonpolar end of the surfactant increases oil solubility (Adkins et al., 2012). The best surfactants used in EOR applications normally have a branched tail.

B. Influence of oil properties on IFT

High specific gravity crude oils are normally rich in organic acids; thus, the surfactant-oil solubility is lower in such oils. Some correlations have been found for the tendency of a surfactant to dissolve in oil as the temperature increases. For many anionics, higher temperatures correspond to better solubility in brine. This behavior is reversed for nonionics. In conclusion, cosurfactants can be used to enhance solubility so that the transition from type II (-) system to type II (+) system can occur at different salinities (Romsted, 2014).

C. Influence of surfactant concentration on IFT

It is necessary to find an optimal concentration because surfactants get adsorbed by the rock. When a large amount of surfactant gets adsorbed, the concentration in the solution decreases and the surfactant capacity to lower interfacial tension is reduced (Donaldson et al. ,1989). Cayias et al. (1977) reported that IFT decreases as the surfactant concentration increases, and at critical concentration the IFT approaches its minimum value. Beyond this critical concentration, the IFT increases with increase of surfactant concentration. Sharma et al. (1983) indicated that adding a nonionic surfactant containing phosphate ester can widen the IFT minimum.

V. Phase behavior

Microemulsion systems can be designed that have ultralow IFT values with either aqueous or hydrocarbon phase. Ultralow IFT are associated with high solubilization of oil and water by the microemulsion system. Thus, regions of low IFT are found by examining the phase behavior of microemulsion systems to locate regions of high solubilization. The phase behavior of microemulsions is complex and there are no universal equations of state for even simple microemulsions. A microemulsion usually consists of at least three components: surfactant, hydrocarbon, and water.

Cosurfactant and electrolyte could be added though are not necessary. The number of components must be reduced due to time and economic constraints by combining one or more components into pseudocomponents. In most cases, the surfactant and cosurfactant are treated as pseudocomponent named as “surfactant”. Water and electrolyte are represented by the brine pseudocomponent (Green and Willhite, 1998). On a ternary diagram such as the one shown in Figure 1-5, by convention, the top apex of the diagram represents the surfactant pseudocomponent, the lower left apex represents brine and the lower right apex represents oil (Reed et al., 1977). Concentrations may be expressed as mass or volume fractions (Green et al., 1998).

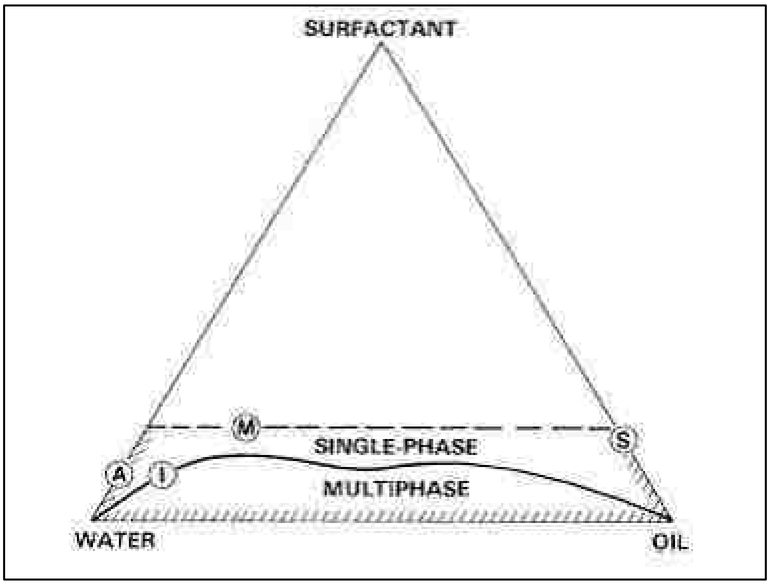

Figure 1-5: Pseudo-ternary representation of oil-water-surfactant system (Reed and Healy,1977)

VI. Wettability

Many researchers including Melrose (1965); McCaffery and Mungan (1970) and Salathiel (1973) suggested that rock wettability can be altered by adding a simple salt, acid or base to flood water.

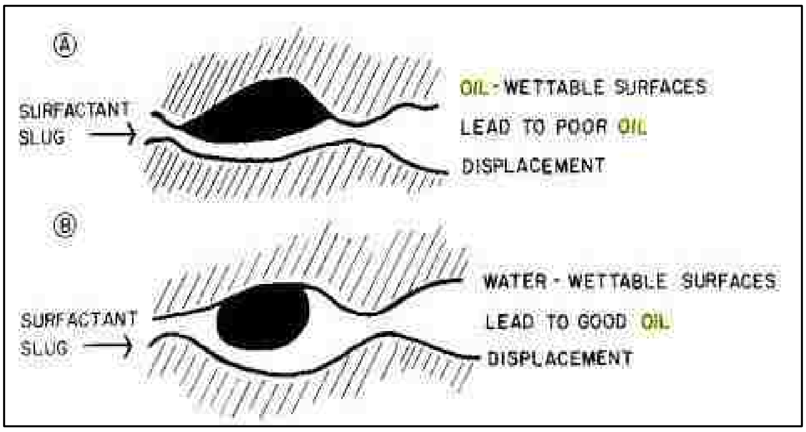

Figure 1-6: The role of wettability and contact angle on oil displacement (Donaldson et al., 1989)

As can be seen in Figure 1-7, the oil-wettable surface leads to poor oil displacement, while the water wettable surface leads to more efficient oil displacement. Choosing an appropriate surfactant can selectively change the rock wettability from oil to water that can facilitate favorable conditions for efficient oil displacement (Donaldson et al., 1989).

1.3.4.2.2 Mechanism of Surfactant Loss in Porous Media

Precipitation, phase trapping and adsorption are various mechanisms by which surfactants get trapped by the reservoir rock. A lot of research in the past and recent times have produced ways to technically avoid loss of surfactant through precipitation and phase trapping. This may be achieved by using salt tolerant surfactants (Chinenye, 2010). As the surfactant slug contacts reservoir rock and water, there would be a loss of surfactants due to adsorption at solid-liquid interface. Therefore, only part of the total surfactant injected in the reservoir is available for the displacement process (Donaldson et al., 1989). Many investigators including Ginn (1970); Somasundaran and Grieves (1975) and Bae and Petrick (1976) have examined the adsorption of various petroleum sulfonates on solid-liquid interfaces. It was noted that the maximum adsorption occurs near the critical micelle concentration which is defined as the concentration of surfactants above which micelles form and all additional surfactants added to the system go to micelles. Novosad (1981) studied surfactant adsorption in the presence of short-chain alcohols. He found that surfactant loss can be minimized by the addition of low molecular weight alcohols such as secondary butyl alcohol and n-propanol.

1.3.4.2.3 Application of Surfactant-Based Process in Sandstone Reservoirs

Most applications of surfactant-based EOR processes have been in sandstone reservoirs. Favorable reservoir characteristics in sandstones include high porosity, high permeability and good geologic continuity. Low clay content is important to have low surfactant retention (Aoudia et al., 1995). Many of the current chemicals are more effective at temperatures less than 150ºC. In addition, it is more preferable to have the remaining oil in place more than 25% with a viscosity less than 50 cp (Sheng, 2011). A majority of implemented projects have been in onshore reservoirs because of the salinity effect on surfactants and the need for a reliable source of high quality water (Romsted, 2014). One of the reasons that surfactant EOR is not as common in carbonate reservoirs is that anionic surfactants are highly adsorbed on the rock surface because of the positive charge. Furthermore, anhydrite is often present in carbonates which causes precipitation (Morrow, 1990; Al-Hasihm et al., 1996; Bortalotti et al., 2009; Manrique et al., 2007). Since most of the world’s oil reserves are contained in carbonate reservoirs, the application of surfactant-based methods in carbonate reservoirs has lately become an active area of research as a strategy to increase oil recovery (Treibel et al., 1972; Manrique et al., 2014; Romsted, 2014).

Chapter 2: Reservoir Simulation Model Description

Surfactant flooding through the reservoir can be modeled using the ECLIPSE 100 simulator. The ECLIPSE 100 is a fully–implicit, three-phase, three dimensional general purpose black oil simulator. The surfactant model in ECLIPSE 100 does not provide the detailed chemistry of the process, but rather models the important features of a surfactant flood on a full field basis. The simulation started on 1st of January 2009, and continued for 41 years up to 2050. The simulation run stops once the water cut reaches 90%.

2.1 Gridding and Rock Data

The synthetic reservoir model shown in Figure 2-1 has dimensions 2250' × 1575' × 150'. Each layer has 30 x 21 cells. There grid cells consist of 15 layers, distributed among three geological layers:

- Geological layer 1 represents grid layers 1 to 5
- Geological layer 2 represents to grid layers 6 to 10
- Geological layer 3 represents to grid layers 11 to 15.

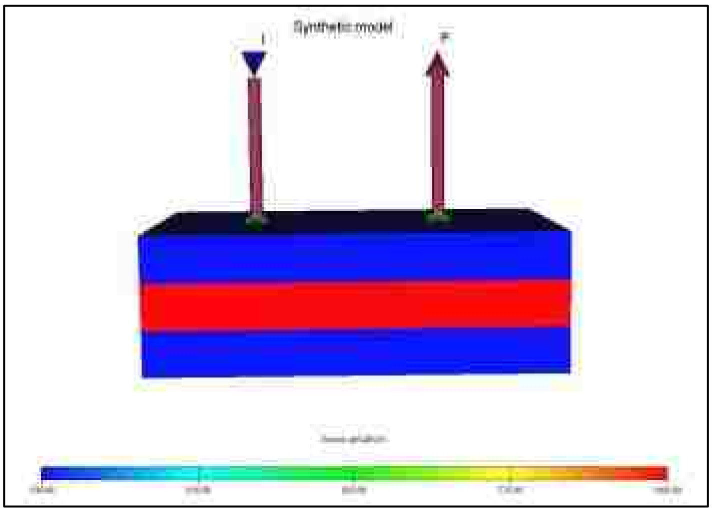

Figure 2-1: Reservoir synthetic model

As illustrated, one injector is located in block number (8, 11) and one producer in block number (22, 11) where both have been completed in the three layers. The depth of the reservoir top is 400o ft. The initial reservoir pressure was 4000 psi at datum depth of 4000 ft and the production bottom hole pressure was 3500 psi. The oil-water contact is below the reservoir (6000 ft), with zero capillary pressure at the contact.

The rock properties are tabulated below.

Table 2-1: Porosity data

Layer number	**Porosity (fraction)**
1	0.20
2	0.22
3	0.20

Table 2-2: Permeability data

	Layer number		
Permeability direction	**1**	**2**	**3**
x-direction	100 md	1000 md	100 md
y-direction	100 md	1000 md	100 md
z-direction	10 md	10 md	100 md

2.2 Fluid PVT and Fluid-Rock Interaction properties:

- Water and oil relative permeability and capillary pressures functions:

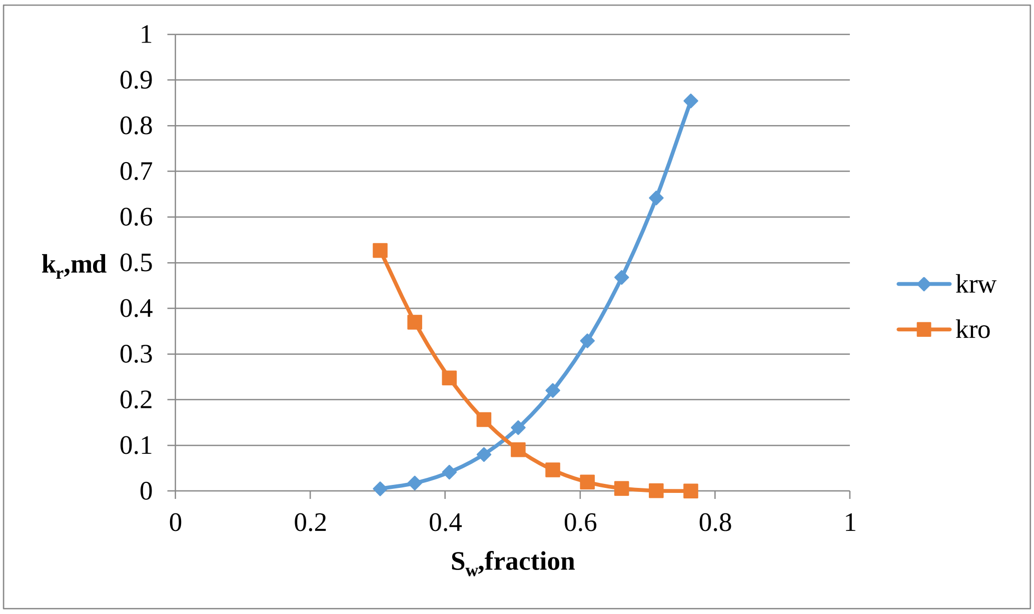

Figure 2-2: Relative permeability curves

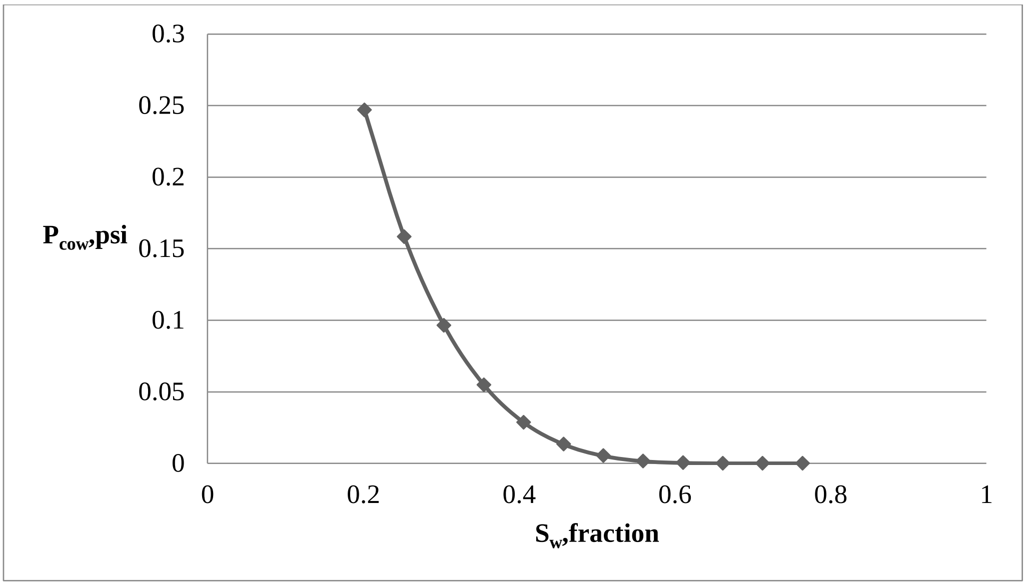

Figure 2-3: Capillary pressure curve

- Water PVT data at reservoir pressure and temperature:

Table 2-3: Water PVT data

Pressure (psia)	B_w (rb/stb)	c_w (psi^{-1})	μ_w (cP)
4500	1.02	3.0E-06	0.8

- Oil PVT data, bubble point pressure (P_b) = 300 psi:

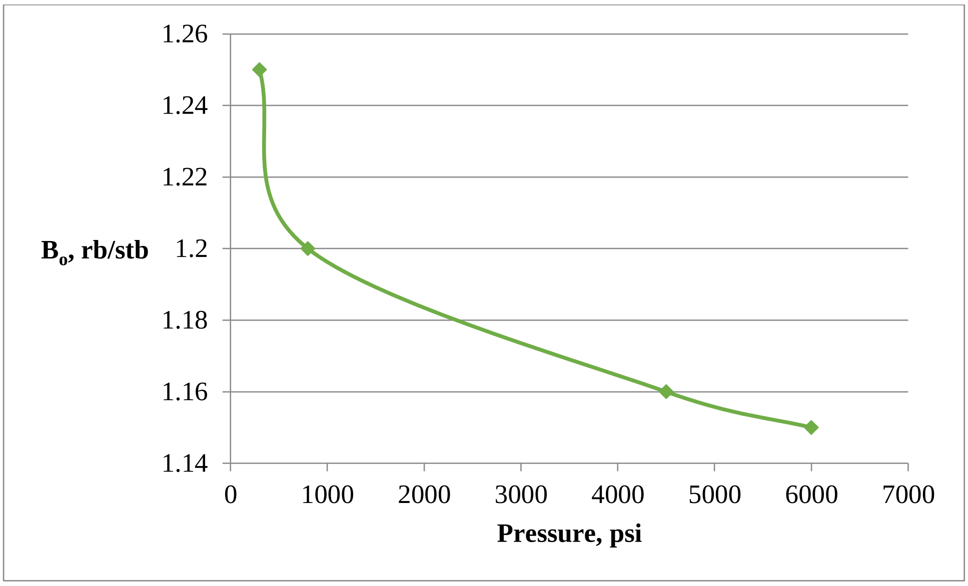

Figure 2-4: Oil formation volume factor as function of pressure

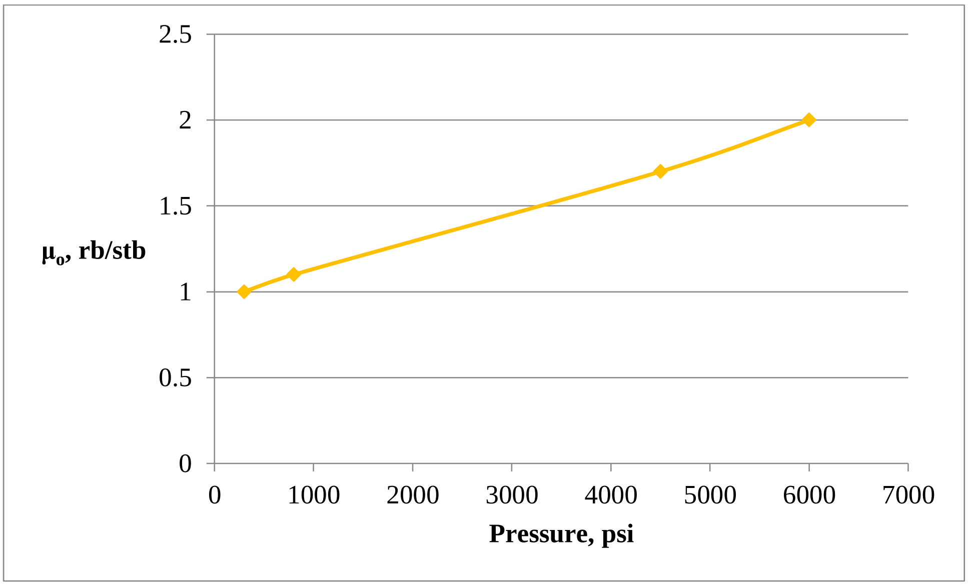

Figure 2-5: Oil viscosity as a function of pressure

- Rock compressibility at 4500 psi= 4E-06 psi^{-1}.

- Oil density at surface conditions= 49 lb/cf.
- Water density at surface conditions= 63 lb/cf.

2.3 Surfactant Properties

The surfactant properties are tabulated below.

Table 2-4: Surfactant solution viscosity

Surfactant concentration (lb/stb)	Water viscosity (cP)
0.0	1.25
30.0	1.20

Table 2-5: Surfactant adsorption isotherm

Surfactant concentration (lb/stb)	Adsorbed mass (lb/lb)
0.0	0.0000
1.0	0.0000
30.0	0.0005

Table 2-6: Water/oil surface tension as a function of surfactant concentration

Surfactant concentration (lb/stb)	Water/Oil surface tension (lb/in)
0.0	0.44
1.0	8.8E-06
30.0	8.8E-06

Table 2-7: Capillary desaturation function

Log_{10}(Capillary number)	Miscibility function
-9.0	0.0
-4.5	0.0
-2.0	1.0
10.0	1.0

2.4 Assumptions

The following assumptions were considered regarding the synthetic reservoir simulation model:

- The injection pattern is not fully patterned as illustrated in Figure 2-4, where a direct line drive can be assumed between the injection and production wells.
- No flow boundary.

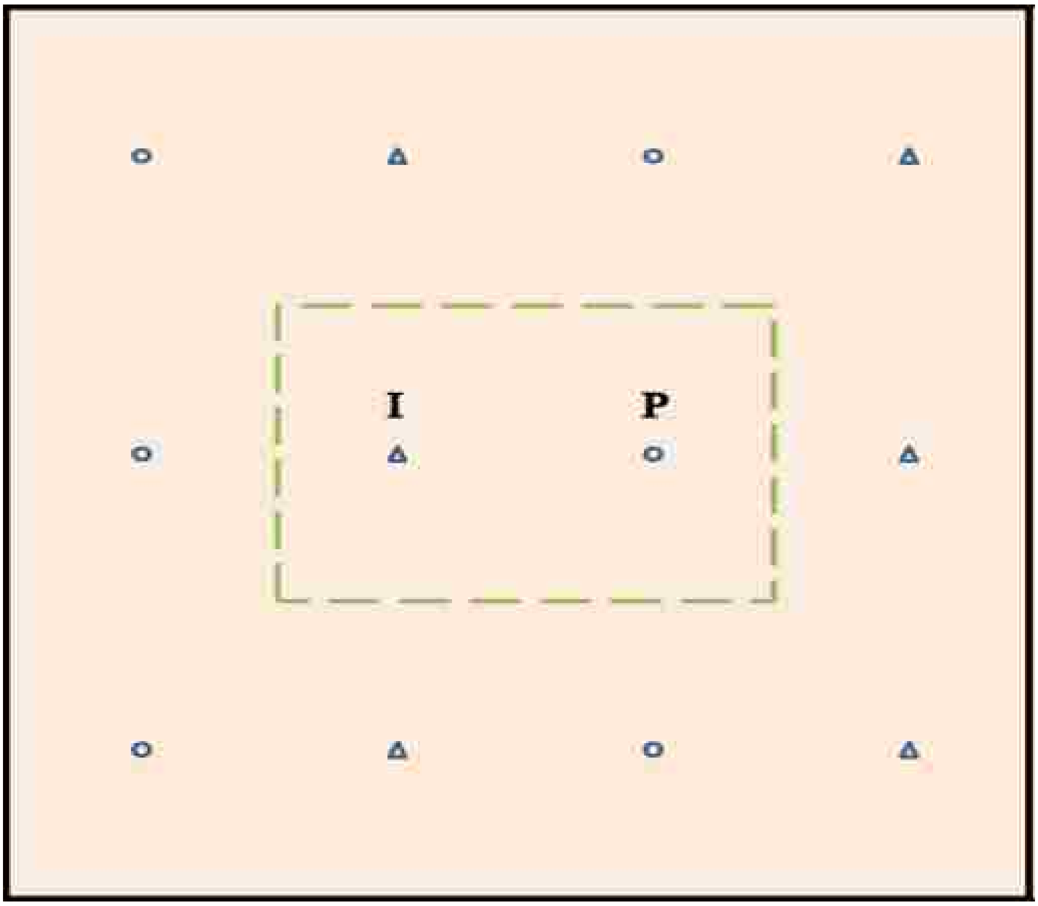

Figure 2-6: Model injection pattern

Chapter 3: Reservoir Development and Development Options

3.1 Reservoir Development Plan

Figure 3-1 presents a reservoir development plan that consists of two key components, pilot-field tests and development option identification. The dependent variables of the technical ultimate recovery are described through the development option, where it mainly encompasses the following:

- Development process,
- Development scheme,
- Reservoir management,
- Business plan.

This plan forms a basis for this piece of work, where different development processes will be examined.

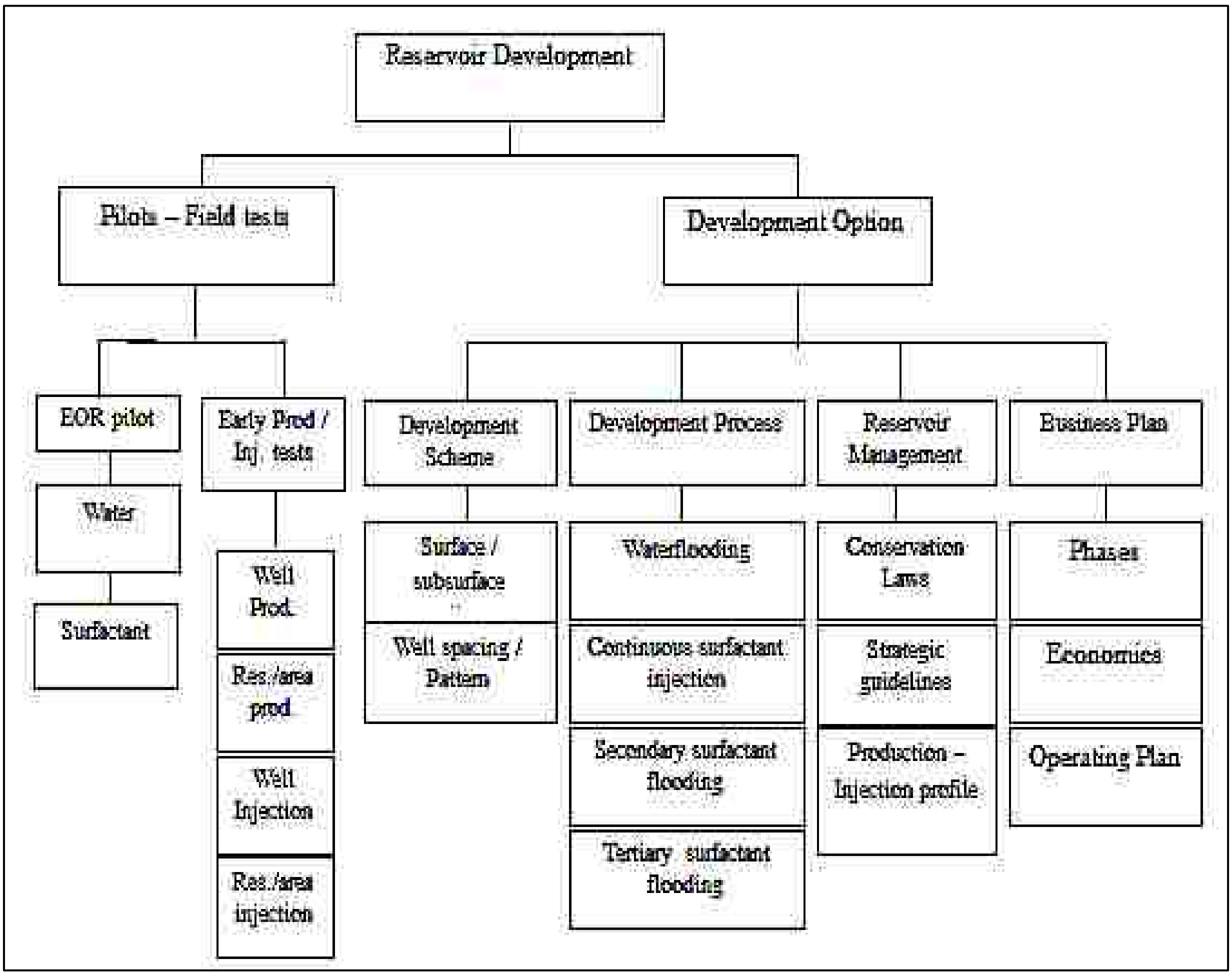

Figure 3-1: Full field development plan optimization (Abed, 2008)

3.2 Reservoir Development Option Identification

The assessment and selection of the development option that will maximize the oil recovery needs to be defined through viable development options and processes.

In defining the constraints, all dependent variables that will affect the results of the study will be considered (Abed, 2008).

In addition, two development processes were identified:

- Waterflooding
- Surfactant flooding

For the surfactant flooding process, the following development injection plans will be analyzed:

- Continuous surfactant injection
- Secondary surfactant flooding
- Tertiary surfactant flooding

Through the study the effect of injection rate, surfactant concentration and surfactant slug size were investigated.

- Surfactant slug size
    - Secondary flooding: 0.1,0.3,0.5 and 0.7 PV.
    - Tertiary flooding: 0.1,0.2,0.25 and 0.3 PV.
- Surfactant concentration (1,25,30 and 35 lb/stb).
- Injection rate (1000,2000 and 3000 stb/d).

The injection rate is set for the surfactant and water injection and are equal in all cases. Tables 4-1 to 4-4 present the development processes identified through the study. A total of 111 simulation runs were prepared and run using the ECLIPSE 100 simulator, where all the scenarios indicated in the followed tables were considered.

Table 3-1: Waterflooding process identification

Development Process	**Timing (years)**	**Surfactant Concentration (lb/stb)**	**Injection Rate (stb/d)**
Waterflooding	Continuous water injection for 41 years (2009 - 2050)	0	1000
			2000
			3000

Table 3-2: Continuous surfactant injection process identification

Development Process	Timing (years)	Surfactant Concentration (lb/stb)	Injection Rate (stb/d)
Continuous surfactant injection	Continuous surfactant injection for 41 years (2009 - 2050)	1	1000
			2000
			3000
		25	1000
			2000
			3000
		30	1000
			2000
			3000
		35	1000
			2000
			3000

Table 3-3: Secondary surfactant flooding process identification

Development Process	Surfactant slug size (PV)	Surfactant Concentration (lb/stb)	Injection Rate (stb/d)
Secondary surfactant flooding	0.1 PV	1	1000
			2000
			3000
		25	1000
			2000
			3000
		30	1000
			2000
			3000
		35	1000
			2000
			3000
	0.3 PV	1	1000
			2000
			3000
		25	1000
			2000
			3000
			1000

		30	2000
			3000
		35	1000
			2000
			3000
	0.5 PV	1	1000
			2000
			3000
		25	1000
			2000
			3000
		30	1000
			2000
			3000
		35	1000
			2000
			3000
	0.7 PV	1	1000
			2000
			3000
		25	1000
			2000
			3000
		30	1000
			2000
			3000
		35	1000
			2000
			3000

Table 3-4: Tertiary surfactant flooding process identification

Development Process	**Surfactant slug size (PV)**	**Surfactant Concentration (lb/stb)**	**Injection Rate (stb/d)**
Tertiary surfactant flooding	0.1 PV	1	1000
			2000
			3000
		25	1000
			2000
			3000
		30	1000
			2000
			3000
		35	1000
			2000
			3000
	0.2 PV	1	1000
			2000
			3000
		25	1000
			2000
			3000
		30	1000
			2000
			3000
		35	1000
			2000
			3000
	0.25 PV	1	1000
			2000
			3000
		25	1000
			2000
			3000
		30	1000
			2000
			3000
		35	1000
			2000
			3000
	0.3 PV		1000

		1	2000
			3000
		25	1000
			2000
			3000
		30	1000
			2000
			3000
		35	1000
			2000
			3000

Chapter 4: Development Processes Assess Study

Two processes were defined, waterflooding and surfactant flooding. For the surfactant flooding process, three development processes were investigated.

The main development processes are continuous surfactant injection, secondary surfactant injection, and tertiary surfactant injection.

Different sensitivities were handled for both processes as defined in chapter 3. In case of waterflooding, the effect of injection rate was examined. However, for the surfactant flood process, the sensitivities were carried on the effect of different injection rate, surfactant concentration and surfactant slug size.

4.1 Sensitivity Analysis

4.1.1 Waterflooding process

As stated previously, the prediction runs were simulated by studying the effect of:

Injection rate (1000, 2000, 3000 stb/d).

The 2000 stb/d is the base case injection rate. The results of the three simulation runs are shown in Tables 4-1 to 4-3 and Figures 4-1 to 4-3.

The main results of each run throughout the study are summarized by the following terms as follows:

- FOE: Field Oil Efficiency (%)
- FOPT: Field Oil Production Total (stb)
- FPR: Field Pressure (psia)
- FWCT: Field Water Cut (dimensionless)
- FWIT: Field Water Injection Total (stb)

- FWPT: Field Water Production Total (stb)
- FTITSUR: Field Surfactant Injection Total (lb)
- FTPTSUR: Field Surfactant Production Total (lb)

Table 4-1: Waterflooding injection at 1000 stb/d results

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Water	5.4257E+06	1.5156E+07	9.0223E+06	0.0	0.0	40.66

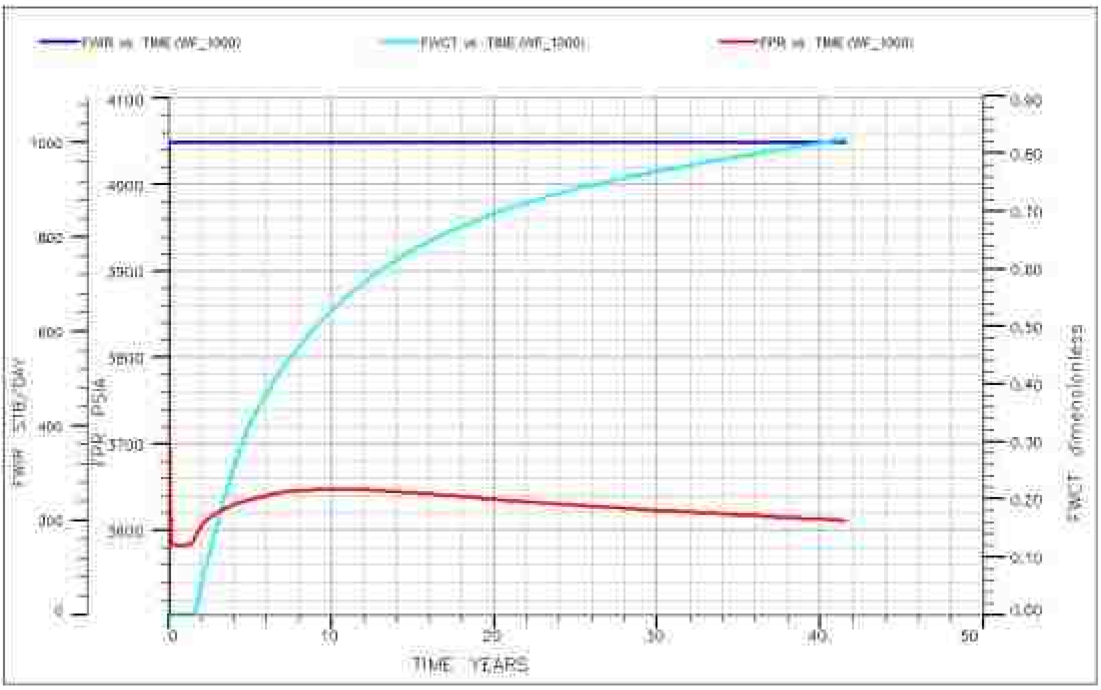

Figure 4-1: Waterflooding injection at 1000 stb/d reservoir performance

Table 4-2: Waterflooding injection at 2000 stb/d results

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Water	5.9925E+06	2.3376E+07	1.6577E+07	0.0	0.0	44.91

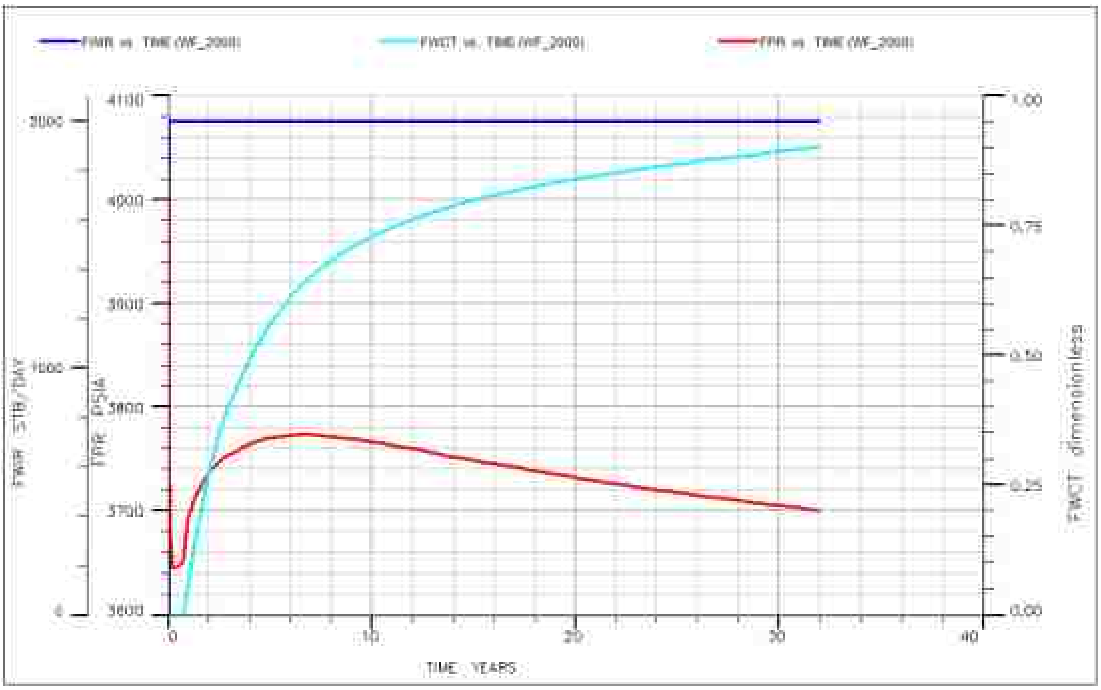

Figure 4-2: Waterflooding injection at 2000 stb/d reservoir performance

Table 4-3: Waterflooding injection at 3000 stb/d results

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Water	6.5648E+06	14787E+07	7.2438E+06	0.0	0.0	42.99

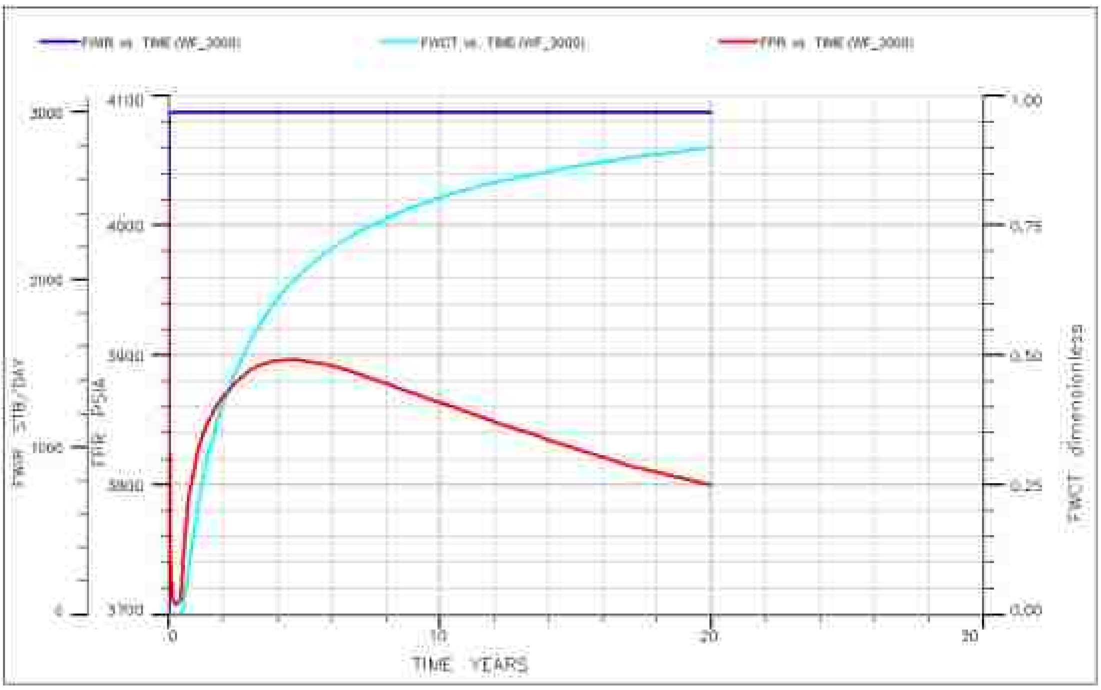

Figure 4-3: Waterflooding injection at 3000 stb/d reservoir performance

According to the illustrated results, the following conclusions can be drawn:

- The injection rate was set constant throughout all runs.
- The water cut economic limit which is 90% was not reached after the 41 years which is the entire simulation period when water was injected at 1000 stb/d. On the other hand, the water cut economic limit was reached after 32 years with the 2000 stb/d injection rate and after 20 years with the 3000 stb/d.
- Increasing the water injection rate leads to reaching the water cut economic limit in a shorter time.

- Early water breakthrough was observed in the three cases.
- Following the pressure drawdown period which lasted for almost a year in all cases, the pressure started to build up since the effect of water injection has been felt.

Table 4-4 shows the oil recovery obtained for the different injection rates. Figure 4-4 shows the oil recovery efficiency profile for the different cases and Figure 4-5 is a bar graph representing FOE at each injection rate attempted.

Table 4-4: Oil recovery efficiency for different injection rates, waterflooding process

Injection rate (stb/d)	FOE (%)	Date
1000	40.66	01 Jan 2050
2000	44.91	01 Jan 2041
3000	42.91	01 Jan 2029

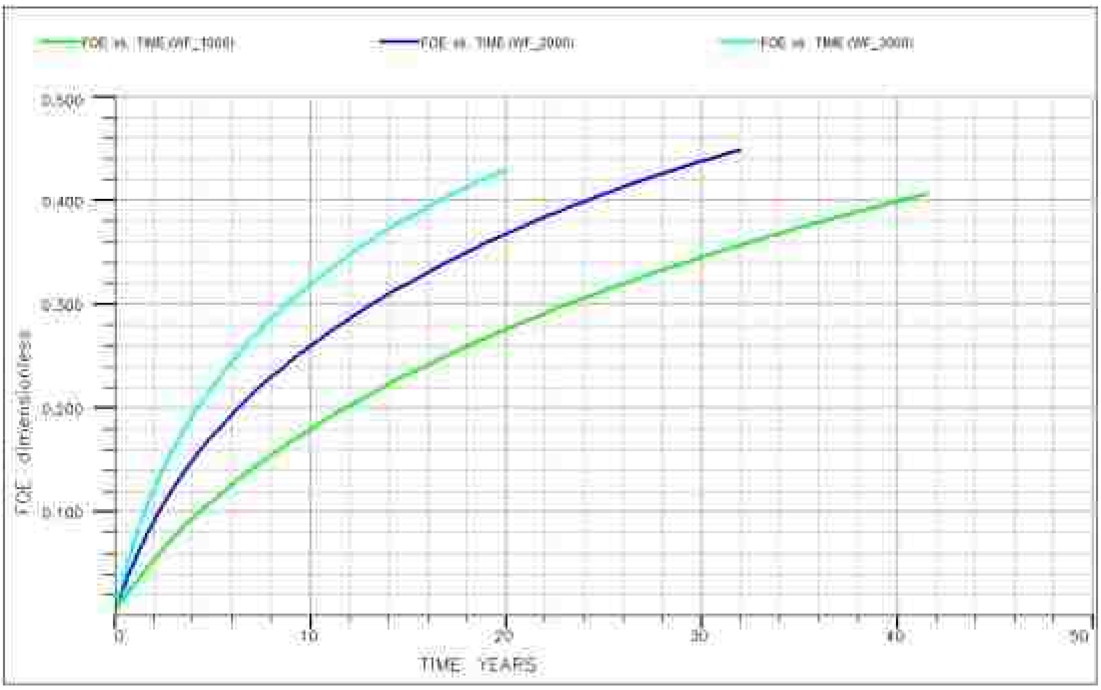

Figure 4-4: Oil recovery efficiency for different injection rates, waterflooding process

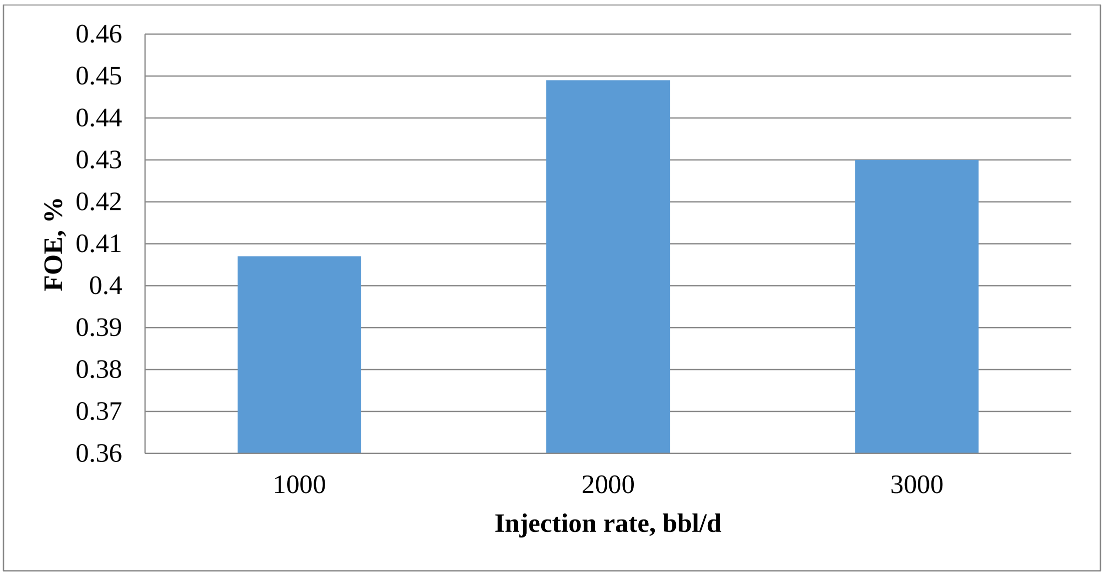

Figure 4-5: FOE vs. injection rate, waterflooding process

As shown above, the maximum oil recovery was achieved at an injection rate of 2000 stb/d. Increasing the injection rate from 1000 to 2000 stb/d increased the recovery by 10%. Injecting water at 3000 stb/d resulted in about 4% decrease in the recovery since the water cut limit was reached relatively earlier which lead to shutting in the oil producer.

4.1.2 Surfactant Flooding Processes

The forecast runs attempted were simulated by studying the effect of different parameters on the performance of the flood as follows, where three different development processes were studied:

- Continuous surfactant injection
  - Surfactant concentration (1,25,30 and 35 lb/stb)
  - Injection rate (1000, 2000, and 3000 stb/d)
- Secondary surfactant flooding
  - Surfactant slug size (0.1, 0.3,0.5 and 0.7 PV)

- Surfactant concentration (1,25,30 and 35 lb/stb)
- Injection rate (1000, 2000, and 3000 stb/d)

- Tertiary surfactant flooding
  - Surfactant slug size (0.1, 0.2 and 0.3 PV)
  - Surfactant concentration (1,25,30 and 35 lb/stb)
  - Injection rate (1000, 2000, and 3000 stb/d)

Figure 4-6 is a graphic representation of the different surfactant flooding development options investigated throughout the study along with normal waterflooding process.

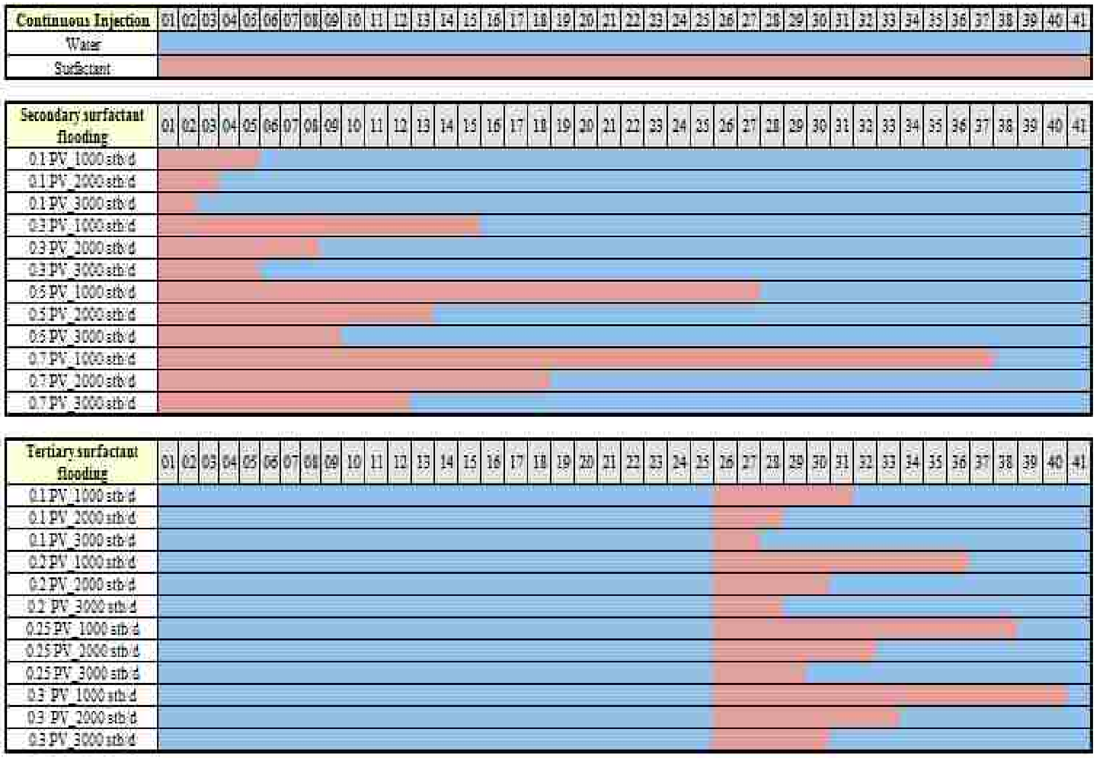

Figure 4-6: Schematics of surfactant flooding development processes

It is important to note at this stage that ECLIPSE 100 assumes that the surfactant exists only in the water phase, and the input to the reservoir is specified as a concentration at the water injector.

I. Continuous Surfactant Injection

Twelve runs were simulated using ECLIPSE 100 and the effect of different surfactant concentrations and injection rates were studied. The results of three runs all at 30 lb/stb surfactant concentration and at different injection rates are presented in Tables 4-5 to 4-7 and Figures 4-7 to 4-9. Similar trends and results were obtained for other surfactant concentration including 1, 25 and 35 lb/stb. A comparison between all different scenarios will be presented in terms of oil recovery efficiency.

Table 4-5: Continuous surfactant injection results (30 lb/stb, 1000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Surfactant	6.9782E+06	1.5156E+07	7.2095E+06	4.5468E+8	1.7785E+8	52.30

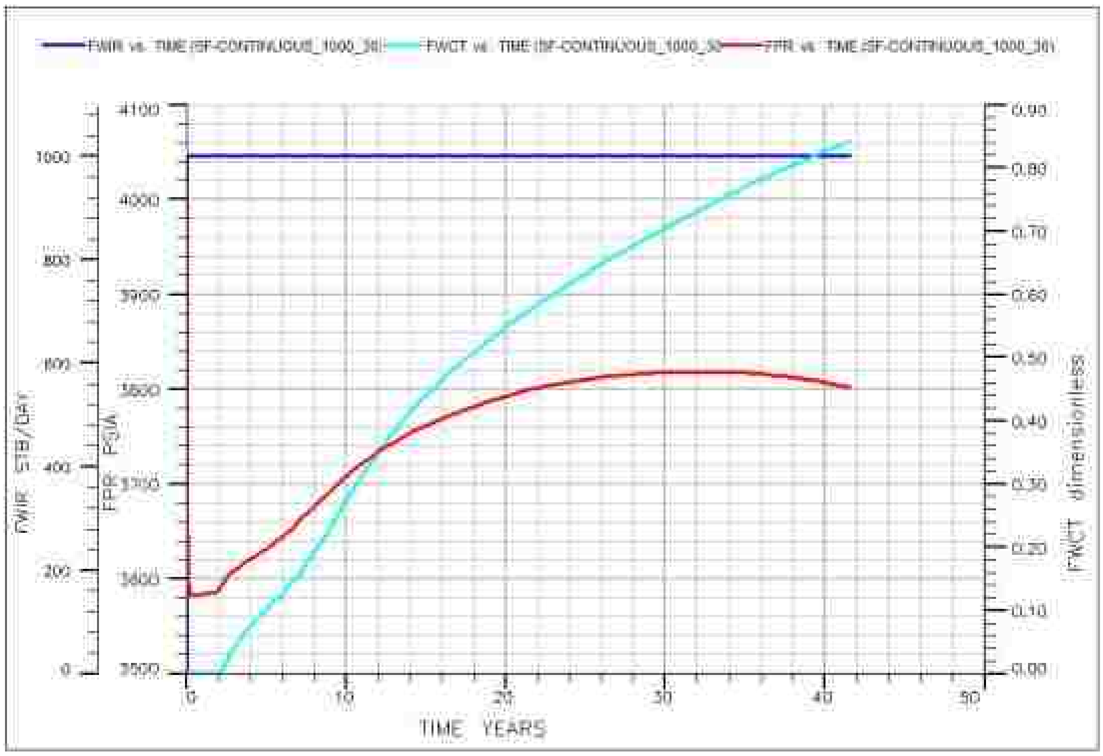

Figure 4-7: Continuous surfactant injection (30 lb/stb, 1000 stb/d) reservoir performance

Table 4-6: Continuous surfactant injection results (30 lb/stb, 2000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Surfactant	7.1819E+06	1.8624E+07	1.0395E+07	5.5872E+8	2.6356E+8	53.82

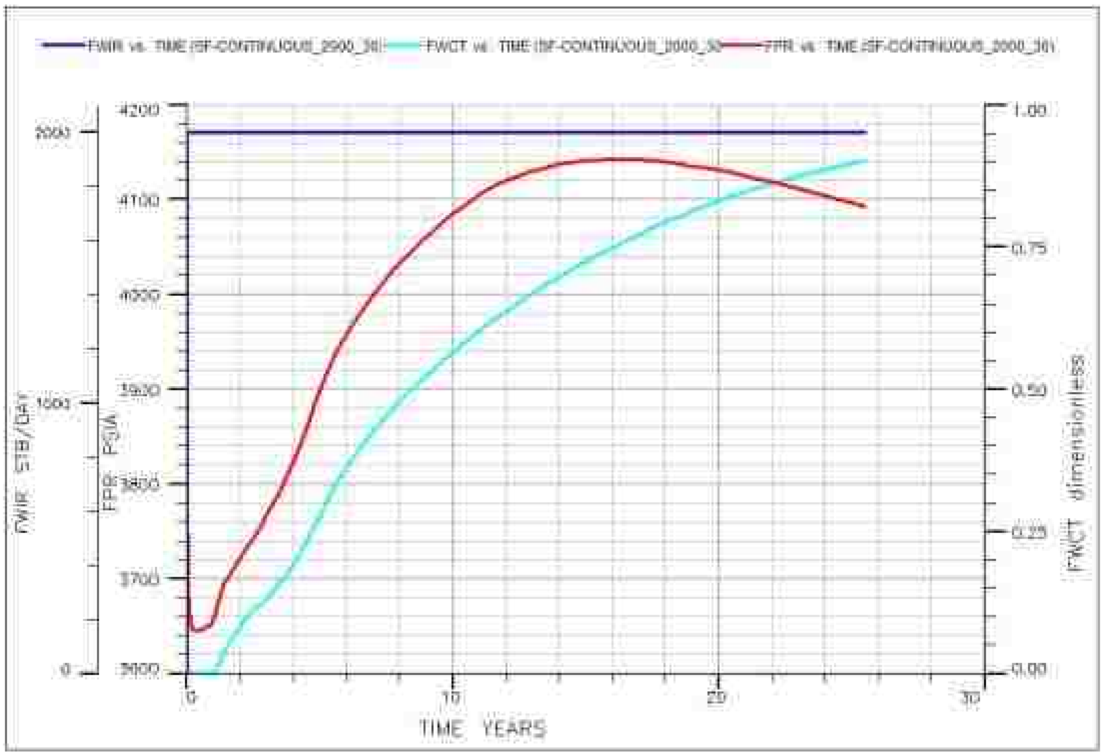

Figure 4-8: Continuous surfactant injection (30 lb/stb, 2000 stb/d) reservoir performance

Table 4-7: Continuous surfactant injection results (30 lb/stb, 3000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Surfactant	7.0533E+06	1.8627E+07	1.0490E+07	5.5881E+8	2.6768E+8	52.86

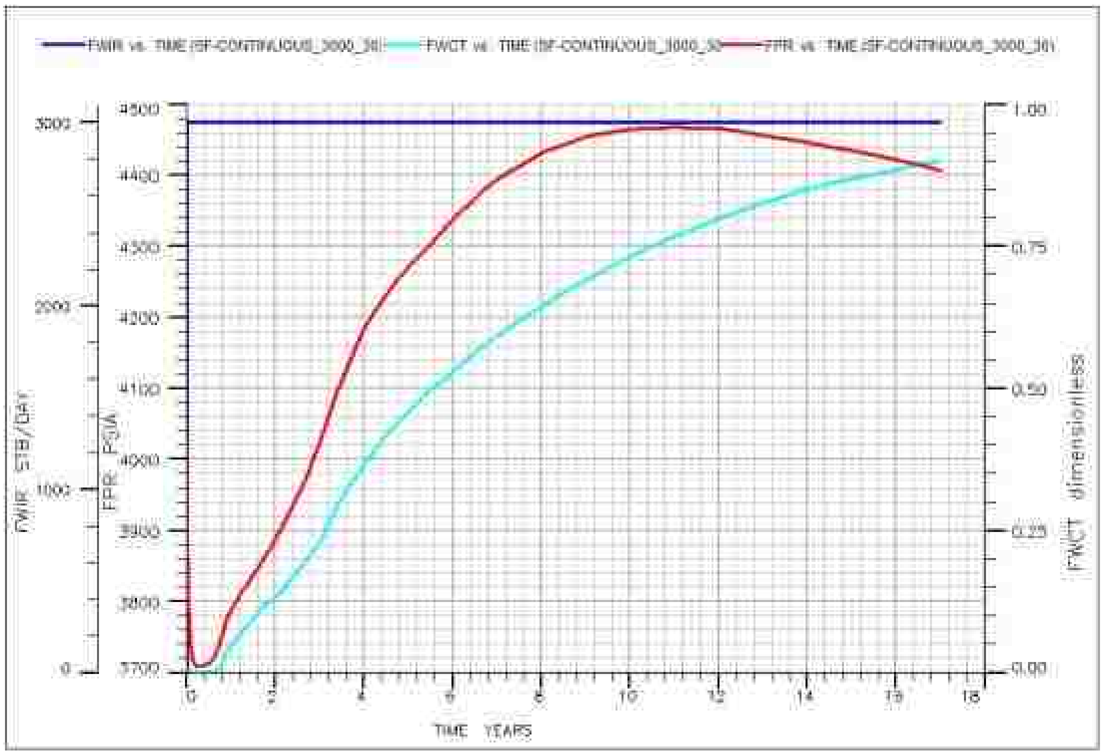

Figure 4-9: Continuous surfactant injection (30 lb/stb, 3000 stb/d) reservoir performance

Based on the results presented at 30 lb/stb where the three different injection rates were attempted, the following findings can be drawn:

- The earliest water breakthrough was experienced when the injection rate was 3000 stb/d.
- As the injection rate time increases, the water breakthrough takes place earlier.
- The water cut limit was not reached after 41 years when water was injected at 1000 stb/d, but it was reached after 26 years with the 2000 stb/d and 17 years with the 3000 stb/d.

- The highest build up plateau was associated with the 3000 stb/d injection rate since the largest volume of water and surfactants were injected in this case.
- The highest total oil produced was achieved with the 2000 stb/d injection rate.

Table 4-8 shows the oil recovery obtained for different surfactant concentrations corresponding to the three injection rates and Figure 4-10 represents the oil recovery efficiency profile for each scenario.

Table 4-8: Oil recovery efficiency for continuous surfactant injection scenarios

Surfactant concentration (lb/stb)	**Injection rate (stb/d)**	**FOE (%)**	**Date**
1	1000	40.87	01 Jul 2050
	2000	45.15	01 Jan 2040
	3000	43.25	01 Jan 2029
25	1000	48.79	01 Jan 2050
	2000	51.66	01 Jan 2037
	3000	50.47	01 Jul 2028
30	1000	52.30	01 Jul 2050
	2000	53.82	01 Jul 2034
	3000	52.86	01 Jan 2026
35	1000	52.60	01 Jul 2050
	2000	54.10	01 Jul 2050
	3000	53.09	01 Jan 2026

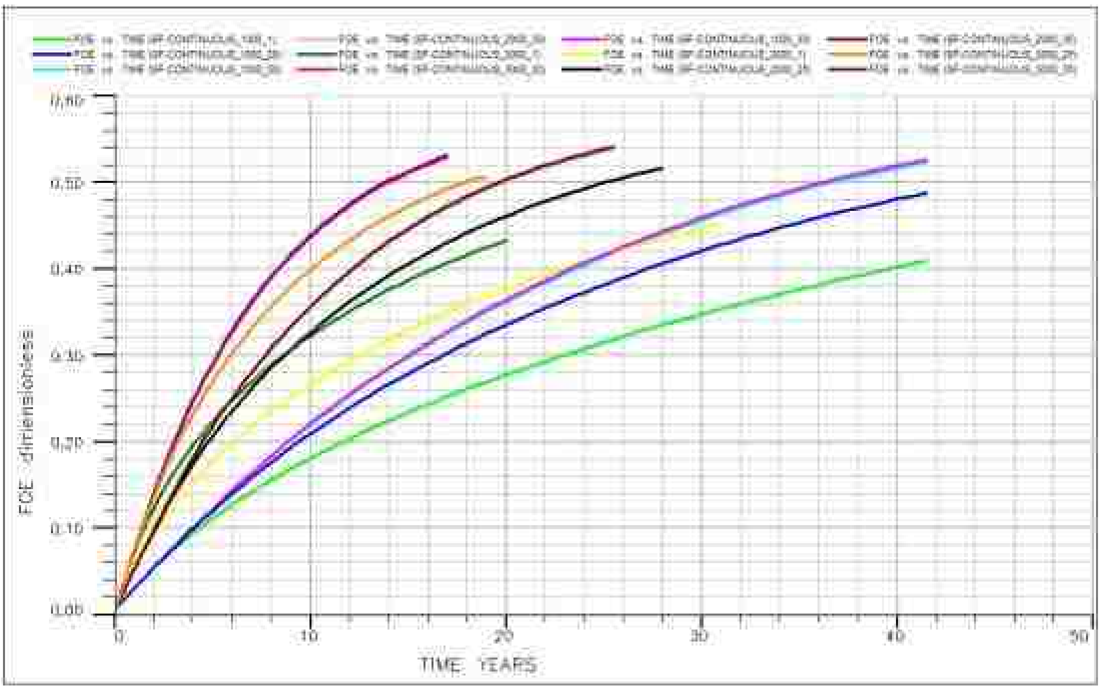

Figure 4-10: Oil recovery efficiency for different scenarios, continuous surfactant injection

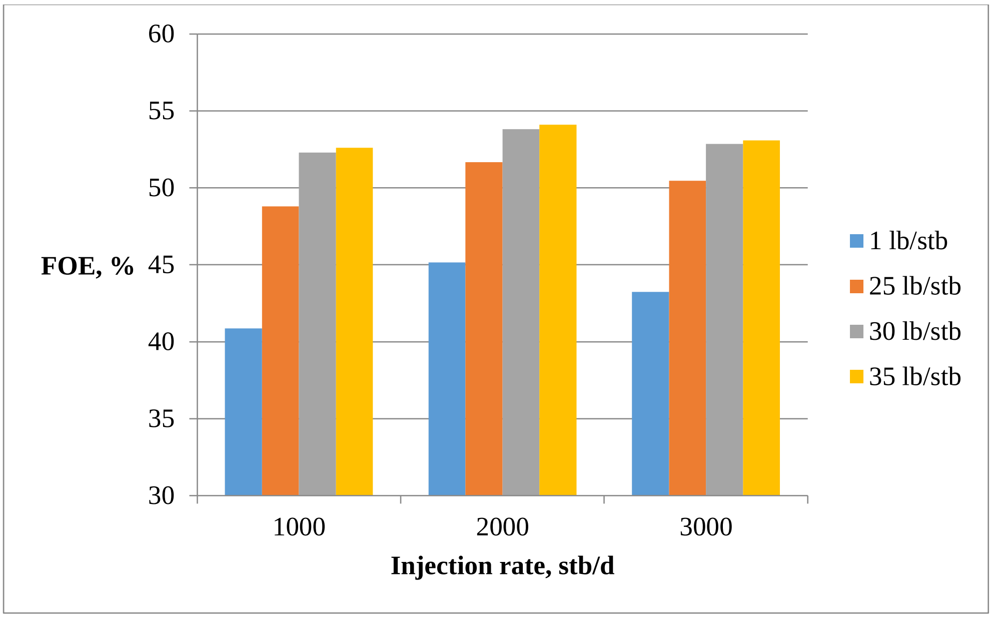

Figure 4-11: FOE vs. injection rate at different surfactant concentrations (continuous surfactant injection)

Based on the data presented above, implementing the continuous surfactant flooding at 2000 stb/d yielded the highest oil recovery efficiency at all surfactant concentrations. Conducting the flood at the lowest surfactant concentration did not result in a significant enhancement in oil recovery over waterflooding. The percentage increase over waterflooding for the 1000, 2000 and 3000 stb/d are 0.51, 0.53 and 0.79 %, respectively. Increasing the surfactant concentration, increased the oil recovery efficiency. It is clearly shown in Table 4-8 that increasing the injection rate at any constant surfactant concentration to 3000 stb/d decreases the oil recovery. This happens because the water cut economic limit is reached in a relatively shorter time compared to the other two cases. Conducting the flood at 35 lb/stb and 2000 stb/d leads to the maximum oil recovery of all cases. The optimum combination can be only determined by calculating the net present value for each combination.

Table 4-9: Percentage increase in FOE at 2000 stb/d (continuous surfactant injection)

Surfactant concentration (lb/stb)	**FOE (%)**	**Percentage Increase-FOE (%)**
1	45.2	-
25	51.7	19.38
30	53.8	7.19
35	54.1	0.57

As seen in Table 4-9, increasing the surfactant concentration at a constant injection rate leads to increase in the oil recovery efficiency. It is clear that increasing the surfactant concentration to 25 lb/stb leads to a significant increase in the recovery efficiency but the increase became less significant when the concentration is increased to 30 lb/stb and almost negligible when the concentration is 35 lb/stb. The same trend was noticed with the other injection rates. Accordingly, conducting the continuous surfactant flooding at 30 lb/stb and 2000 stb/d is considered to the optimum case from the technical point of view.

I. Secondary Surfactant flooding

A total of forty eight runs were simulated using ECLIPSE 100 and the effect of different surfactant slug size, surfactant concentrations and injection rates were studied. The results of four runs all at 30 lb/stb surfactant concentration and 2000 stb/d at four different surfactant slug sizes are presented in Tables 4-10 to 4-13 and Figures 4-12 to 4-15. Similar results and trends were obtained for other surfactant concentration including 1, 25 and 35 lb/stb. A comparison between all different scenarios will be presented in terms of oil recovery efficiency.

Table 4-10: Secondary flooding results (0.1 PV, 30 lb/stb, 2000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Secondary flooding	6.0254E+06	2.1914E+07	1.5077E+07	7.1160E+07	3.8930E+07	45.20

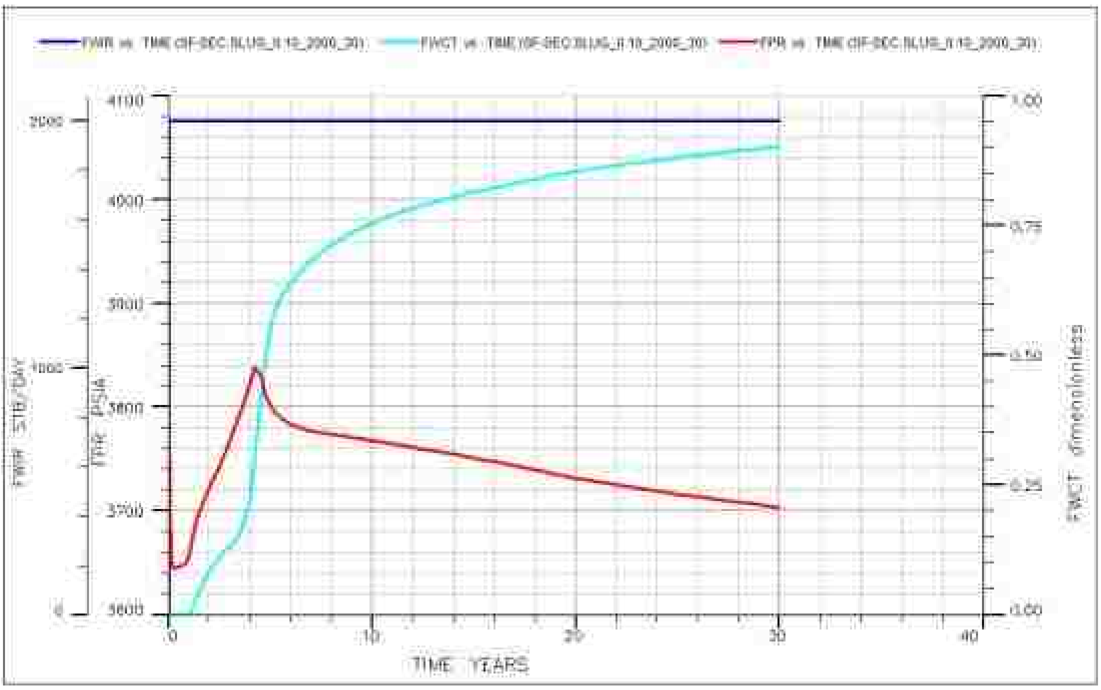

Figure 4-12: Secondary surfactant flooding (0.1 PV, 30 lb/stb, 2000 stb/d) reservoir performance

Table 4-11: Secondary flooding results (0.2 PV, 30 lb/stb, 2000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Secondary flooding	6.0457E+06	1.9722E+07	1.2860E+07	1.3686E+08	6.9585E+07	45.31

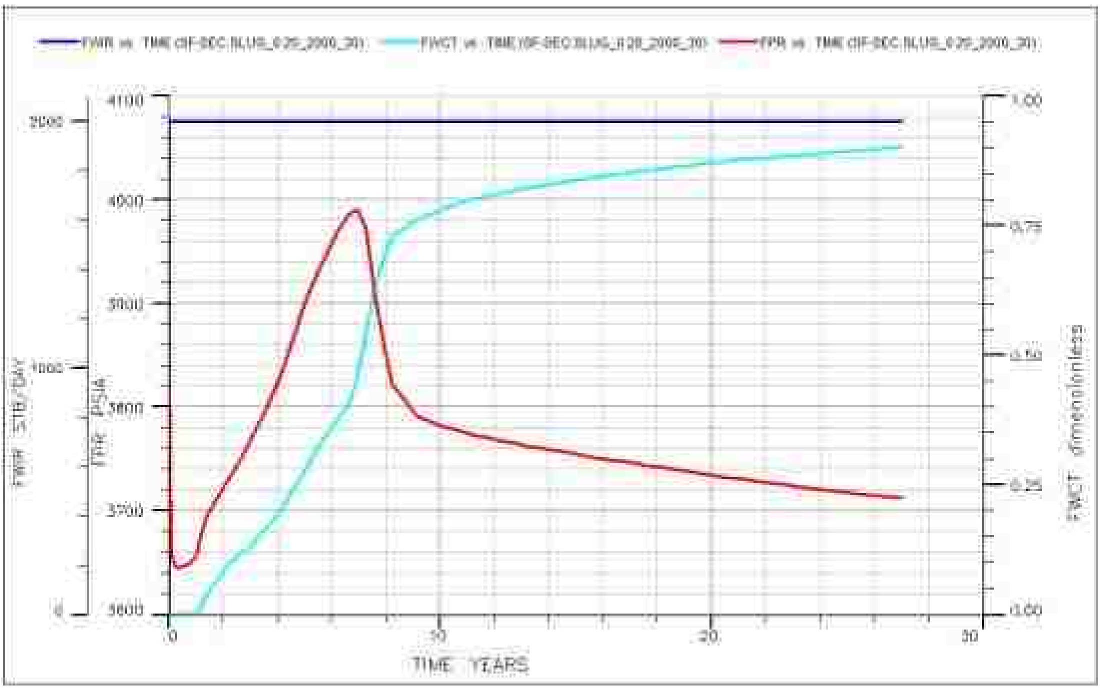

Figure 4-13: Secondary surfactant flooding (0.2 PV, 30 lb/stb, 2000 stb/d) reservoir performance

Table 4-12: Secondary flooding results (0.3 PV, 30 lb/stb, 2000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Secondary flooding	6.0489E+06	1.7894E+07	1.1027E+07	1.8072E+07	8.6517E+07	45.33

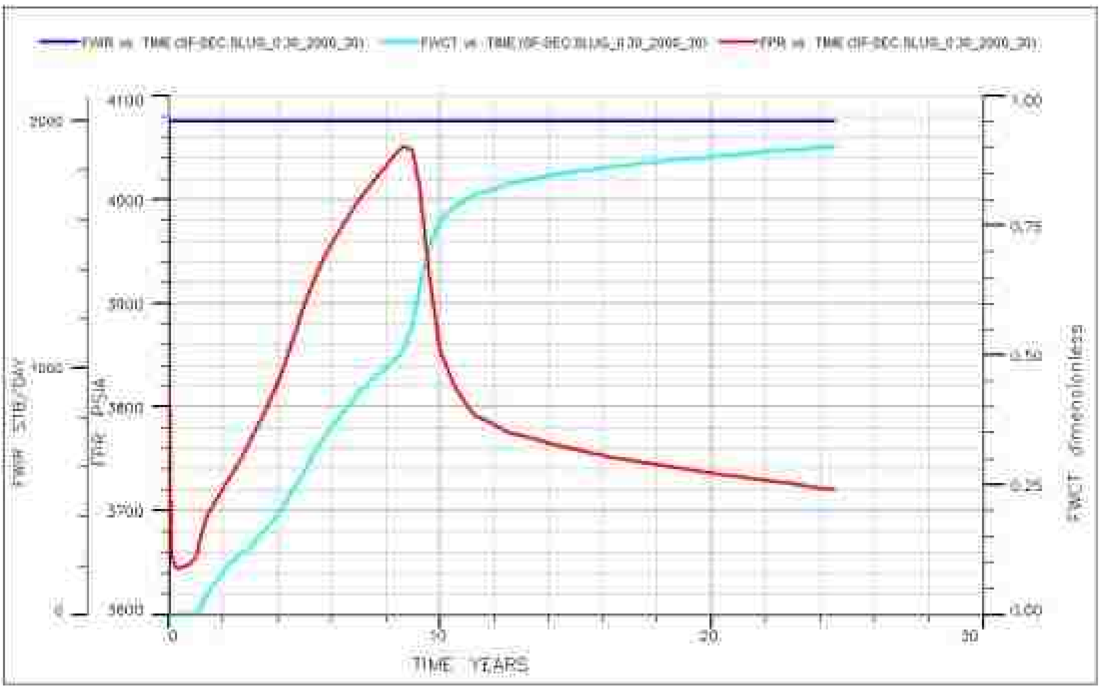

Figure 4-14: Secondary surfactant flooding (0.3 PV, 30 lb/stb, 2000 stb/d) reservoir performance

Table 4-13: Secondary flooding results (0.5 PV, 30 lb/stb, 2000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Secondary flooding	6.1073E+06	1.3328E+07	6.3868E+06	2.9028E+08	1.1525E+08	45.77

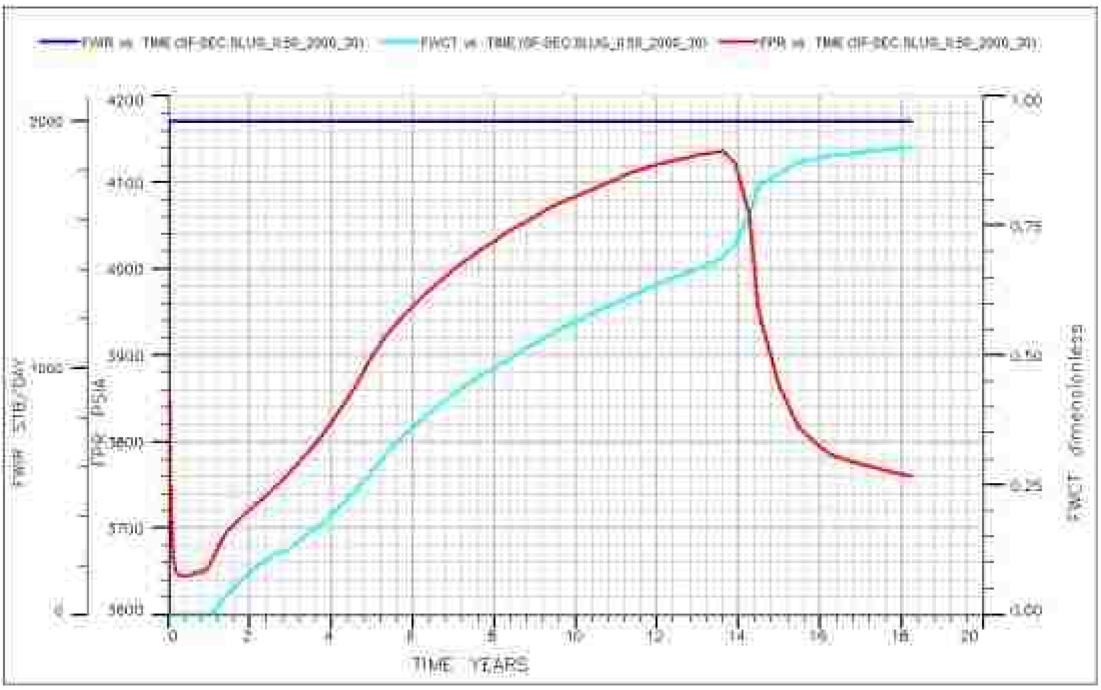

Figure 4-15: Secondary surfactant flooding (0.5 PV, 30 lb/stb, 2000 stb/d) reservoir performance

The results presented above show that pressure build up trends depend on the duration of surfactant and water injection in each case. In the first case where 0.1 PV of surfactant was injected, the pressure increased sharply after a short drawdown period during the surfactant injection period. When water injection started, the pressure decreased gradually. The other cases are similar. They all show that during the surfactant injection, the pressure increases sharply before it decreases gradually due to waterflooding. The highest plateau was associated with the 0.5 PV slug size since the largest volume of surfactants was injected in this case. The gradual decrease in the pressure level during waterflooding takes place due to the opposing gravitational effects. It is important to note that the water cut economic limit was reached in all cases before the end of the simulation period.

Table 4-14 shows the oil recovery efficiency for the various surfactant slug sizes, surfactant concentrations and injection rates. Figures 4-16 to 4-19 represent the oil recovery efficiency for each scenario in graphical form. Figures 4-20 to 4-23 are bar graphs of the oil recovery efficiency for each combination of surfactant slug size, surfactant concentration and injection rate.

Table 4-14: Oil recovery efficiency of secondary flooding scenarios

Surfactant slug size (PV)	**Surfactant concentration (lb/stb)**	**Injection rate (stb/d)**	**FOE (%)**	**Date**
0.1	1	1000	40.68	01 Jul 2050
		2000	44.96	01 Jan 2040
		3000	43.05	01 Jan 2029
	25	1000	41.13	01 Jul 2050
		2000	44.99	01 Jan 2039
		3000	42.96	01 Jan 2028
	30	1000	41.24	01 Jul 2050
		2000	45.20	01 Jan 2039
		3000	42.80	01 Jul 2027
	35	1000	41.20	01 Jul 2050
		2000	45.17	01 Jan 2039
		3000	42.85	01 Jul 2027
	1	1000	40.75	01 Jul 2050
		2000	45.00	01 Jan 2040
		3000	43.09	01 Jan 2029
	25	1000	43.50	01 Jul 2050
		2000	45.40	01 Jan 2040

0.3		3000	42.99	01 Jan 2029
	30	1000	44.59	01 Jul 2050
		2000	45.33	01 Jul 2033
		3000	43.26	01 Jul 2024
	35	1000	44.60	01 Jul 2050
		2000	45.21	01 Jan 2033
		3000	43.47	01 Jul 2024
0.5	1	1000	40.83	01 Jul 2050
		2000	45.06	01 Jan 2040
		3000	43.16	01 Jan 2029
	25	1000	46.33	01 Jul 2050
		2000	45.44	01 Jan 2032
		3000	43.99	01 Apr 2023
	30	1000	48.69	01 Jan 2050
		2000	45.77	01 Apr 2027
		3000	45.26	01 Apr 2021
	35	1000	48.70	01 Jan 2049
		2000	46.13	01 Apr 2027
		3000	45.63	01 Apr 2021
0.7	1	1000	40.87	01 Jul 2050
		2000	45.10	01 Jan 2040
		3000	43.20	01 Jan 2029
	25	1000	48.43	01 Jul 2050
		2000	46.62	01 Apr 2030
		3000	46.01	01 Jul 2023
	30	1000	51.58	01 Jul 2049
		2000	49.77	01 Jan 2029
		3000	49.12	01 Jul 2022
	35	1000	51.93	01 Jul 2049
		2000	50.12	01 Jan 2029
		3000	49.44	01 Jul 2022

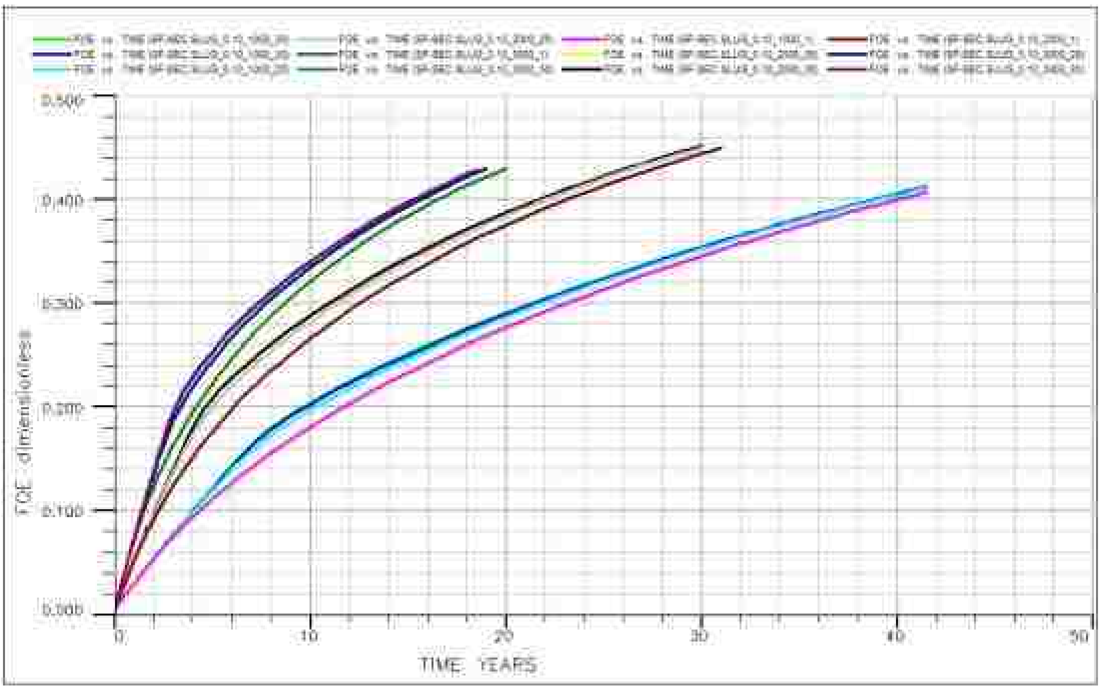

Figure 4-16: Oil recovery efficiency for different scenarios, secondary surfactant flooding_0.1PV

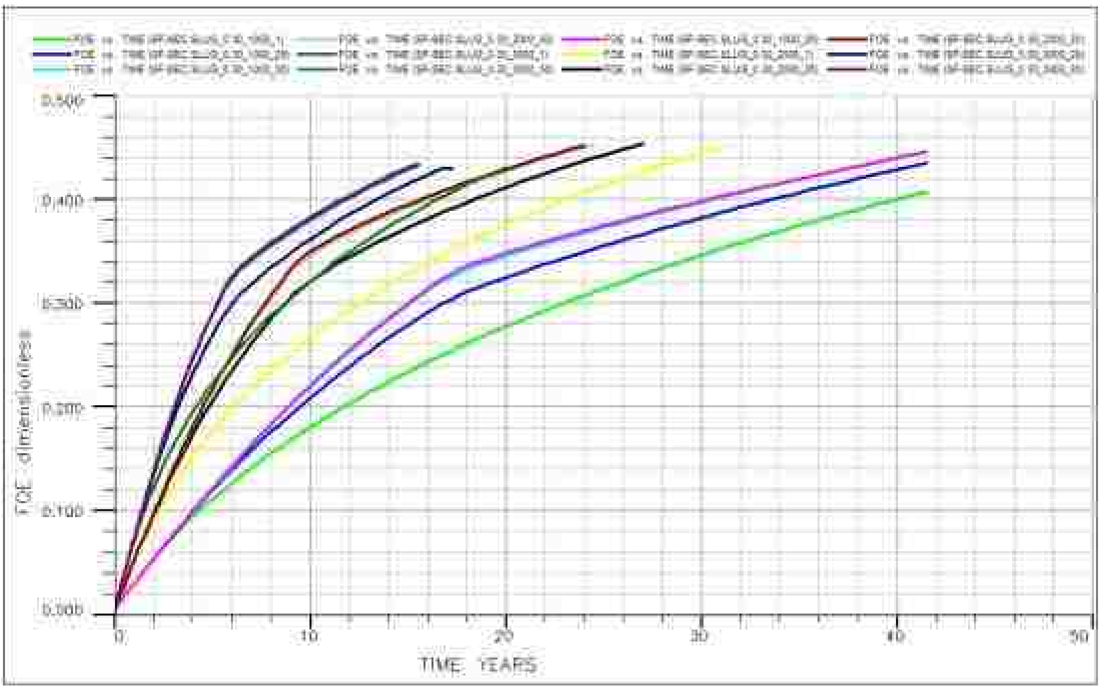

Figure 4-17: Oil recovery efficiency for different scenarios, secondary surfactant flooding_0.3PV

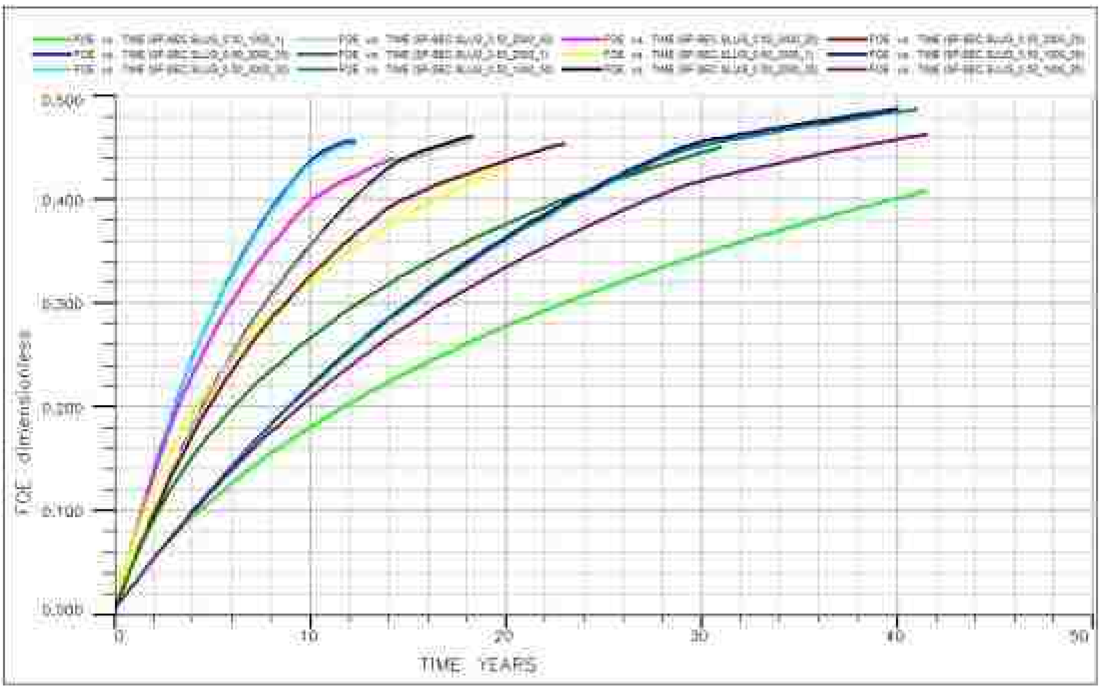

Figure 4-18: Oil recovery efficiency for different scenarios, secondary surfactant flooding_0.5 PV

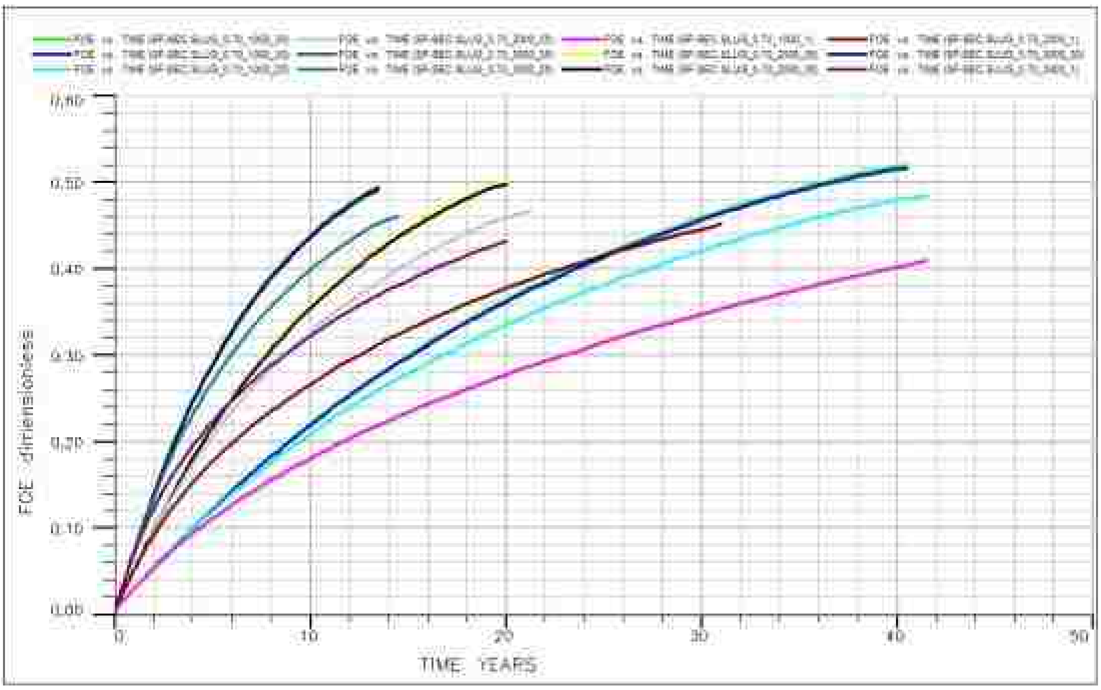

Figure 4-19: Oil recovery efficiency for different scenarios, secondary surfactant flooding_0.7 PV

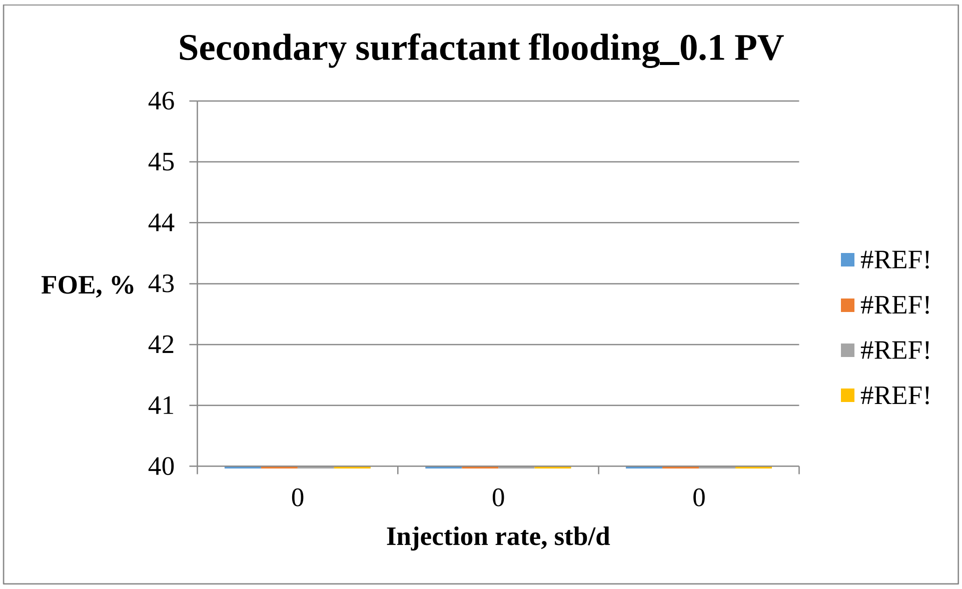

Figure 4-20: FOE vs. injection rate at different surfactant concentrations (secondary surfactant flooding _0.1 PV)

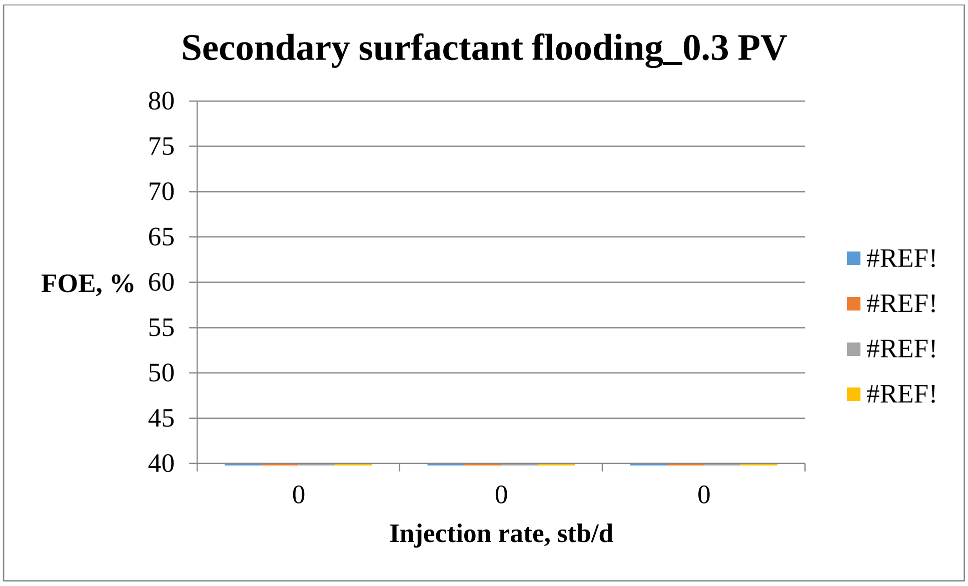

Figure 4-21: FOE vs. injection rate at different surfactant concentrations (secondary surfactant flooding _0.3 PV)

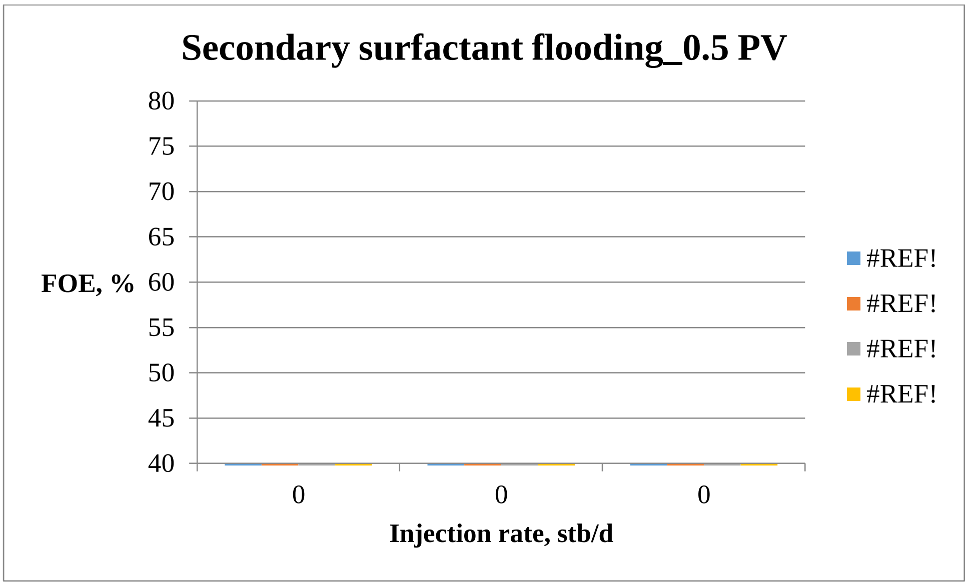

Figure 4-22: FOE vs. injection rate at different surfactant concentrations (secondary surfactant flooding _0.5 PV)

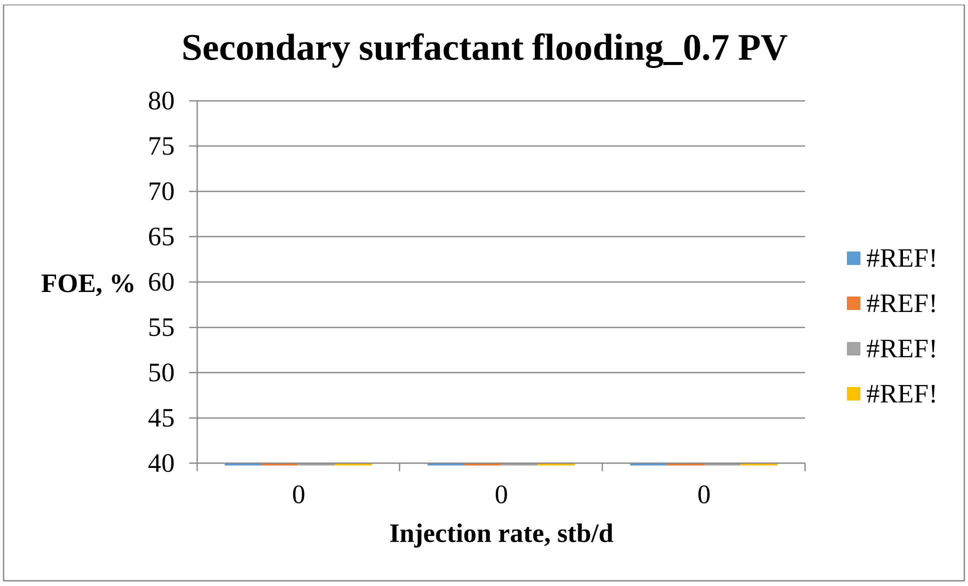

Figure 4-23: FOE vs. injection rate at different surfactant concentrations (secondary surfactant flooding _0.7 PV)

Conducting secondary surfactant flooding at the smallest surfactant slug size and minimum concentration yield a percentage increase of waterflooding of 0.05,0.11 and 0.33 % for the 1000, 2000 and 3000 stb/d which is insignificant. Table 4-14 shows that increasing the surfactant slug size has a positive effect on the oil recovery regardless of the surfactant concentration and injection rate. Increasing the surfactant concentration does not necessarily imply an increase in oil recovery. It is also clear that increasing the injection rate from 1000 to 2000 stb/d increases the oil recovery but increasing the rate to 3000 stb/d has an adverse effect.

Table 4-15: Percentage increase in FOE at 30 lb/stb (secondary surfactant flooding)

Surfactant slug size (PV)	**FOE @ 1000 stb/d (%)**	**Percentage Increase-FOE (%)**	**FOE @ 2000 stb/d (%)**	**Percentage Increase-FOE (%)**	**FOE @ 3000 stb/d (%)**	**Percentage Increase-FOE (%)**
0.1	40.68		45.20		42.80	
0.3	44.59	9.61	45.33	0.29	43.26	1.07
0.5	48.69	9.19	45.77	0.97	45.26	4.62
0.7	51.58	5.94	49.77	8.74	49.12	8.53

The table above shows the effect of increasing the surfactant slug size and injection rate at a specific surfactant concentration. Increasing the surfactant slug size while setting the injection rate at 1000 stb/d and the surfactant concentration at 30 lb/stb shows that the percentage increase in the oil recovery efficiency became less significant as the slug size increased. This not true for the other attempted injection rates. It is clearly shown in the table that the percentage increase in FOE became more significant as the surfactant slug size increased.

Technically, the following table presents the optimum combination of surfactant concentration and injection for the various surfactant slug sizes:

Table 4-16: Optimum combination of surfactant concentration and injection for the different surfactant slug sizes (secondary surfactant flooding)

Surfactant slug size (PV)	Optimum surfactant concentration (lb/stb)	Optimum injection rate (stb/d)
0.1	30	2000
0.3	25	2000
0.5	30	1000
0.7	30	1000

II. Tertiary Surfactant flooding

Forty eight simulation runs were performed to study the effect of implementing tertiary surfactant flooding. The results of four runs all at 30 lb/stb surfactant concentration and at different surfactant slug size and injection rates are presented in Tables 4-17 to 4-20 and Figures 4-24 to 4-27. A comparison between all different scenarios will be presented in terms of oil recovery efficiency.

Table 4-17: Tertiary flooding results (0.1 PV, 30 lb/stb, 2000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Tertiary flooding	1.3186E+05	2.3556E+07	1.6511E+07	8.7660E+07	2.3746E+07	46.50

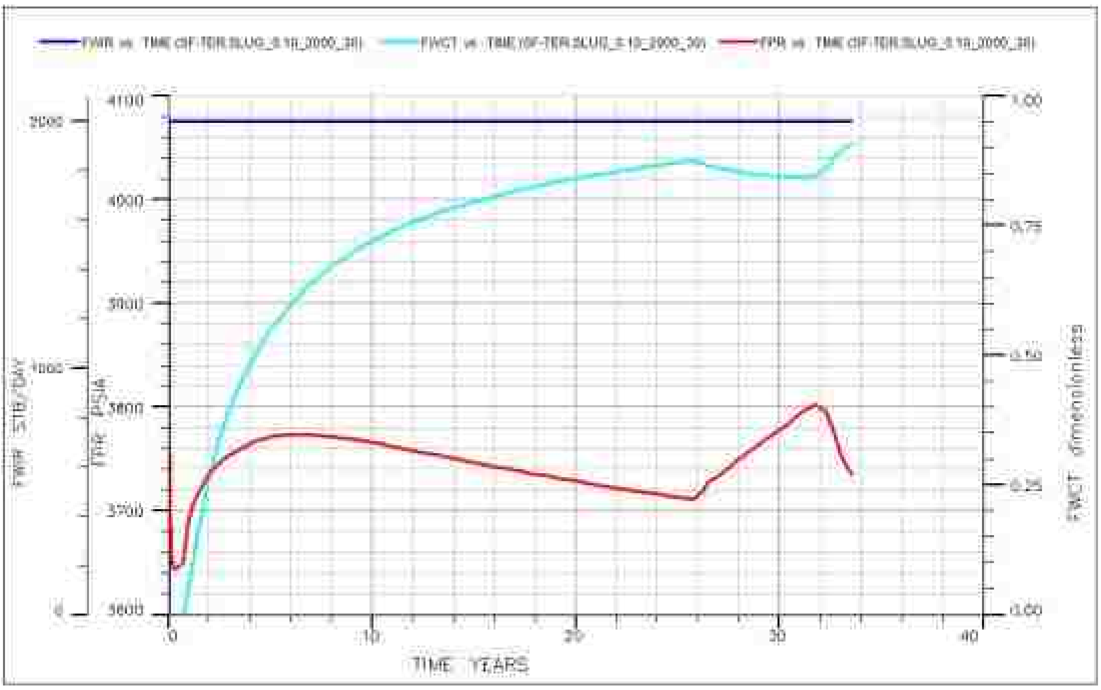

Figure 4-24: Tertiary surfactant flooding (0.1 PV, 2000 stb/d, 30 lb/stb) reservoir performance

Table 4-18: Tertiary flooding results (0.2 PV, 30 lb/stb, 2000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Tertiary flooding	6.3437E+06	2.4286E+07	1.7076E+07	1.3152E+8	3.3569E+07	47.54

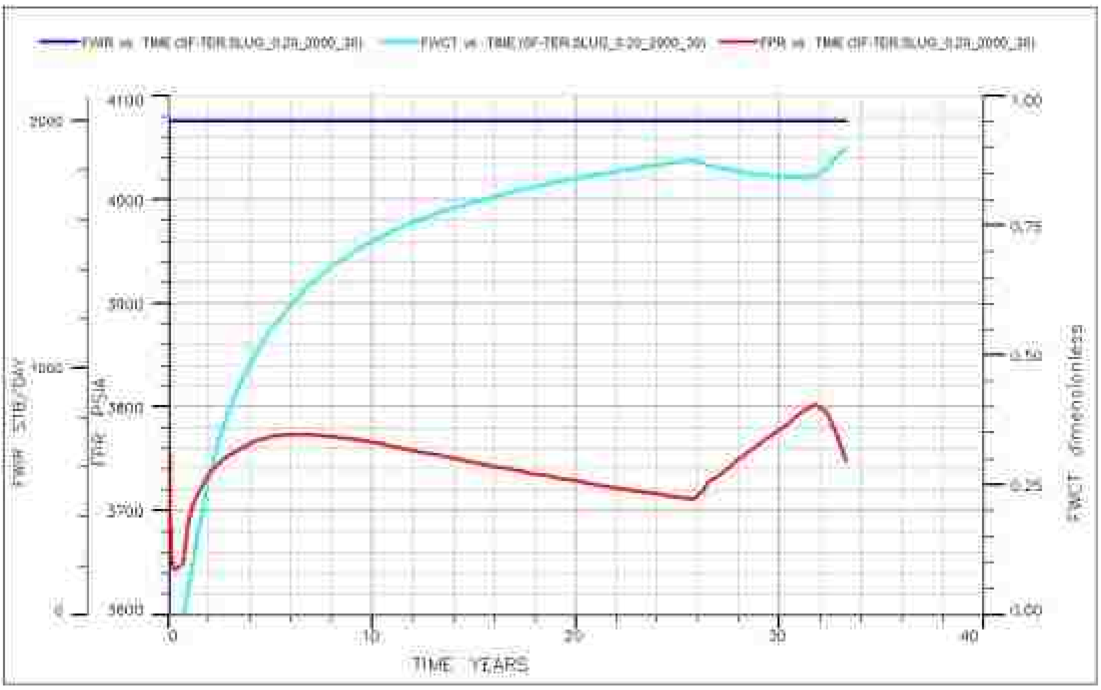

Figure 4-25: Tertiary surfactant flooding (0.2 PV, 2000 stb/d, 30 lb/stb) reservoir performance

Table 4-19: Tertiary flooding results (0.25 PV, 30 lb/stb, 2000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Tertiary flooding	6.5258E+06	2.5566E+07	1.8145E+07	1.7532E+8	4.8266E+07	48.91

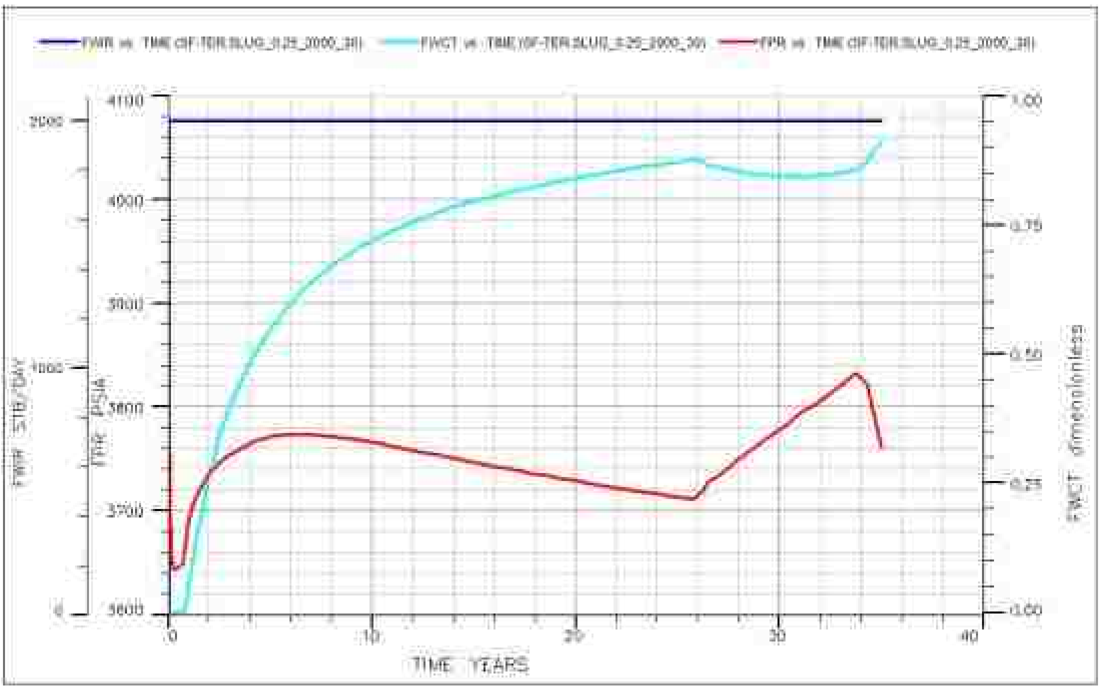

Figure 4-26: Tertiary surfactant flooding (0.25 PV, 2000 stb/d, 30 lb/stb) reservoir performance

Table 4-20: Tertiary flooding results (0.3 PV, 30 lb/stb, 2000 stb/d)

Development Process Results						
Development Process	**FOPT (stb)**	**FWIT (stb)**	**FWPT (stb)**	**FTITSUR (lb)**	**FTPTSUR (lb)**	**FOE (%)**
Tertiary flooding	6.5888E+06	2.5930E+07	1.8430E+07	1.9722E+8	5.3935E+07	49.38

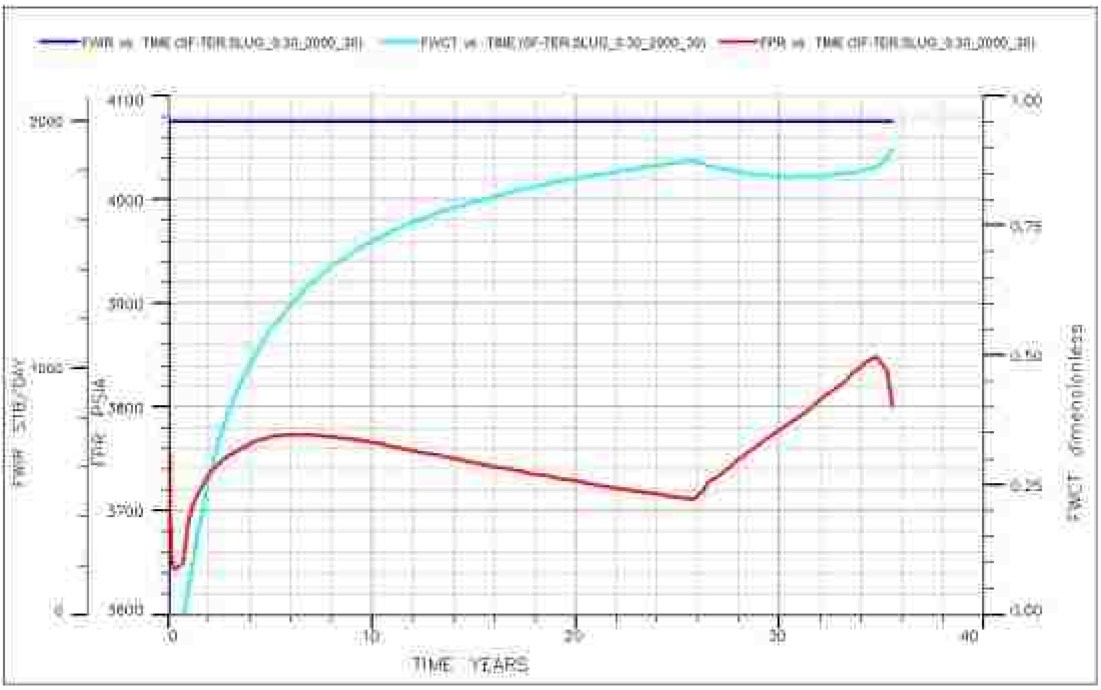

Figure 4-27: Tertiary surfactant flooding (0.3 PV, 2000 stb/d, 30 lb/stb) reservoir performance

The results above show that the pressure build up curves are almost identical. During the water injection, the pressure increased sharply after a drawdown period that lasted for a year. After 8 years of water injection, the pressure decreased gradually to reach almost 3710 psia. The decrease in pressure takes place due to unfavorable gravitational effects. When water injection starts again after the end of surfactant injection, it is clear that the pressure decreased in a sharp manner till the end of the simulation period. The water cut limit was reached before 41 years in all cases. The oil recovery efficiency increased with increasing pore volumes of surfactant injected.

Table 4-21 shows the oil recovery efficiency for the various surfactant slug sizes, surfactant concentrations and injection rates. Figures 4-28 to 4-31 represent the oil recovery efficiency for each scenario in graphical form. Figures 4-32 to 4-35 are bar graphs of the oil recovery efficiency for each combination of surfactant slug size, surfactant concentration and injection rate.

Table 4-21: Oil recovery efficiency of tertiary flooding scenarios

Surfactant slug size (PV)	Surfactant concentration (lb/stb)	Injection rate (stb/d)	FOE (%)	Date
0.1	1	1000	40.70	01 Jul 2050
		2000	45.09	01 Apr 2040
		3000	43.00	01 Jan 2029
	25	1000	41.61	01 Jul 2050
		2000	46.33	01 Apr 2041
		3000	43.00	01 Jan 2029
	30	1000	41.81	01 Jul 2050
		2000	46.50	01 Apr 2041
		3000	43.00	01 Jan 2029
	35	1000	41.92	01 Jul 2050
		2000	46.62	01 Apr 2041
		3000	43.00	01 Jan 2029
0.2	1	1000	40.73	01 Jul 2050
		2000	45.10	01 Apr 2040
		3000	43.00	01 Jan 2029
	25	1000	42.71	01 Jul 2050
		2000	47.22	01 Apr 2042
		3000	43.00	01 Jan 2029
	30	1000	43.29	01 Jul 2050
		2000	47.54	01 Apr 2042
		3000	43.00	01 Jan 2029
		1000	43.49	01 Jul 2050

	35	2000	47.72	01 Apr 2042
		3000	43.00	01 Jan 2029
0.25	1	1000	40.73	01 Jul 2050
		2000	45.10	01 Apr 2040
		3000	43.00	01 Jan 2029
	25	1000	43.04	01 Jul 2050
		2000	48.41	01 Jan 2044
		3000	43.00	01 Jan 2029
	30	1000	43.78	01 Jul 2050
		2000	48.91	01 Jan 2044
		3000	43.00	01 Jan 2029
	35	1000	43.99	01 Jul 2050
		2000	49.11	01 Jan 2044
		3000	43.00	01 Jan 2029
0.3	1	1000	40.73	01 Jul 2050
		2000	45.23	01 Apr 2041
		3000	43.00	01 Jan 2029
	25	1000	43.12	01 Jul 2050
		2000	48.79	01 Jul 2044
		3000	43.00	01 Jan 2029
	30	1000	43.92	01 Jul 2050
		2000	49.38	01 Jul 2044
		3000	43.00	01 Jan 2029
	35	1000	44.09	01 Jul 2050
		2000	49.82	01 Jan 2045
		3000	43.00	01 Jan 2029

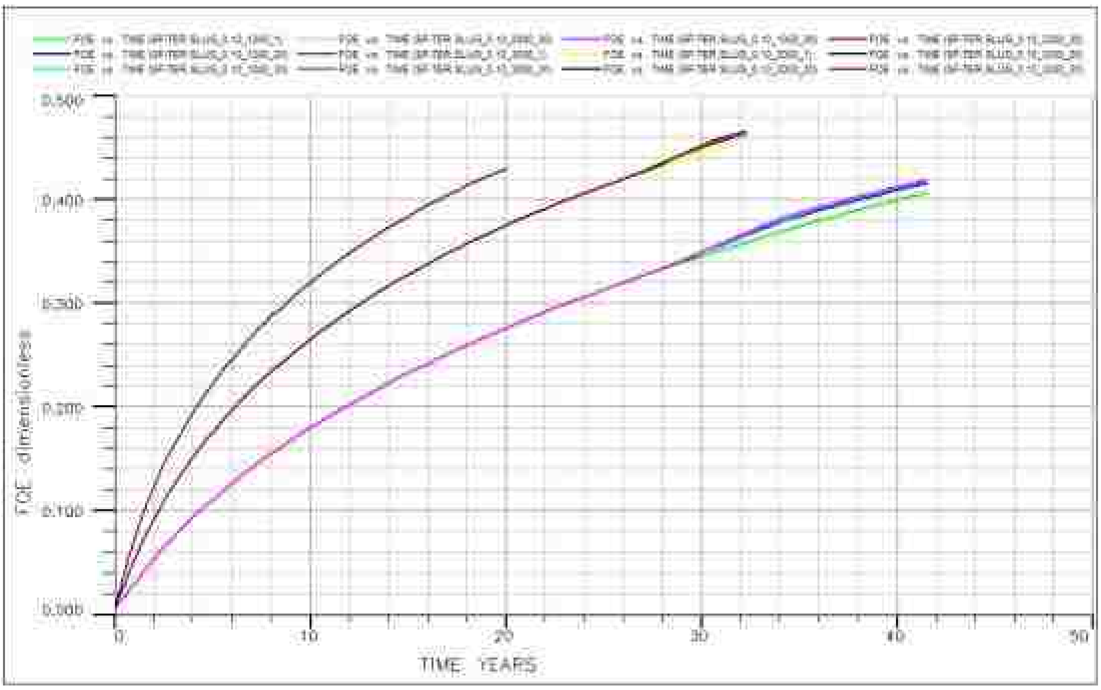

Figure 4-28: Oil recovery efficiency for different scenarios, tertiary surfactant flooding_0.1 PV

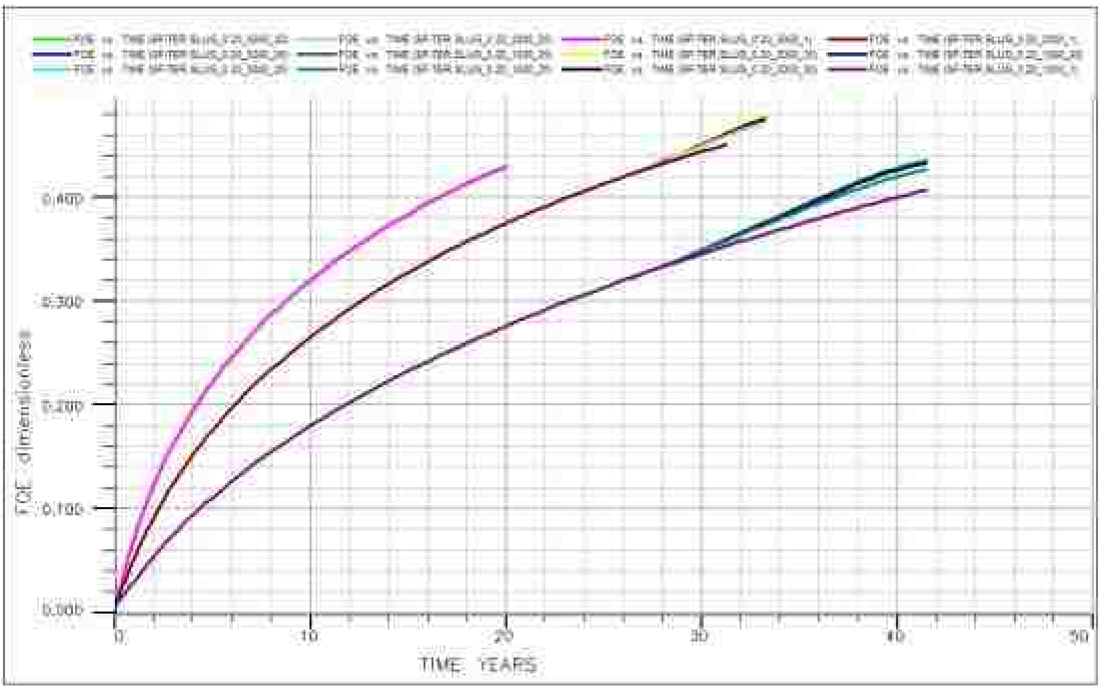

Figure 4-29: Oil recovery efficiency for different scenarios, tertiary surfactant flooding_0.2 PV

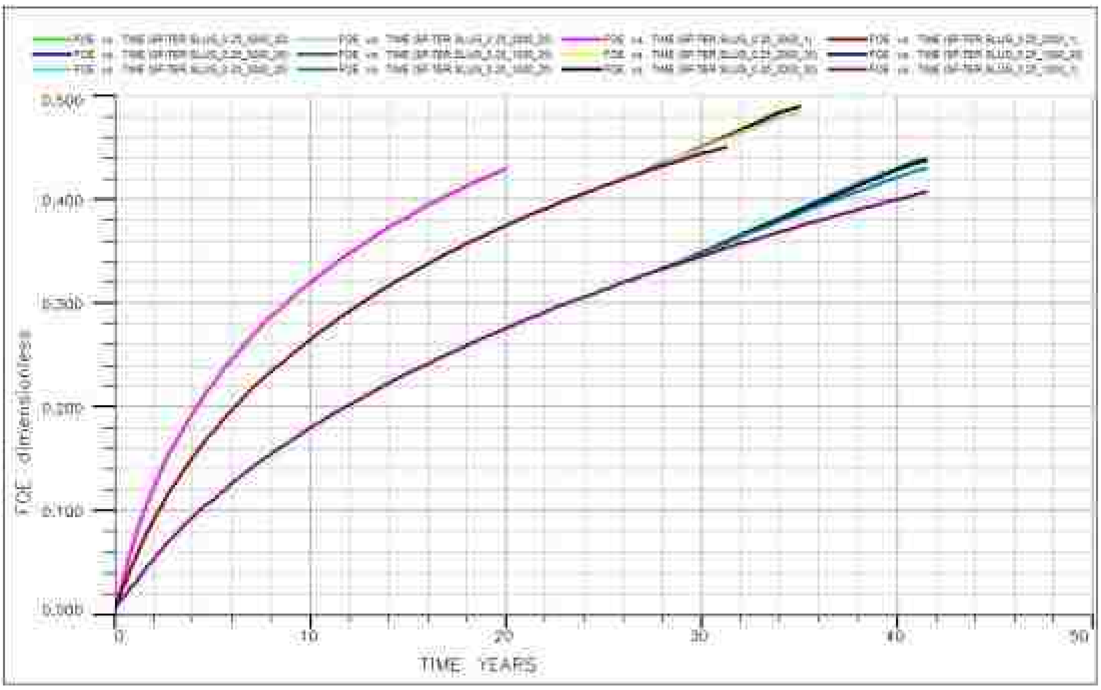

Figure 4-30: Oil recovery efficiency for different scenarios, tertiary surfactant flooding_0.25 PV

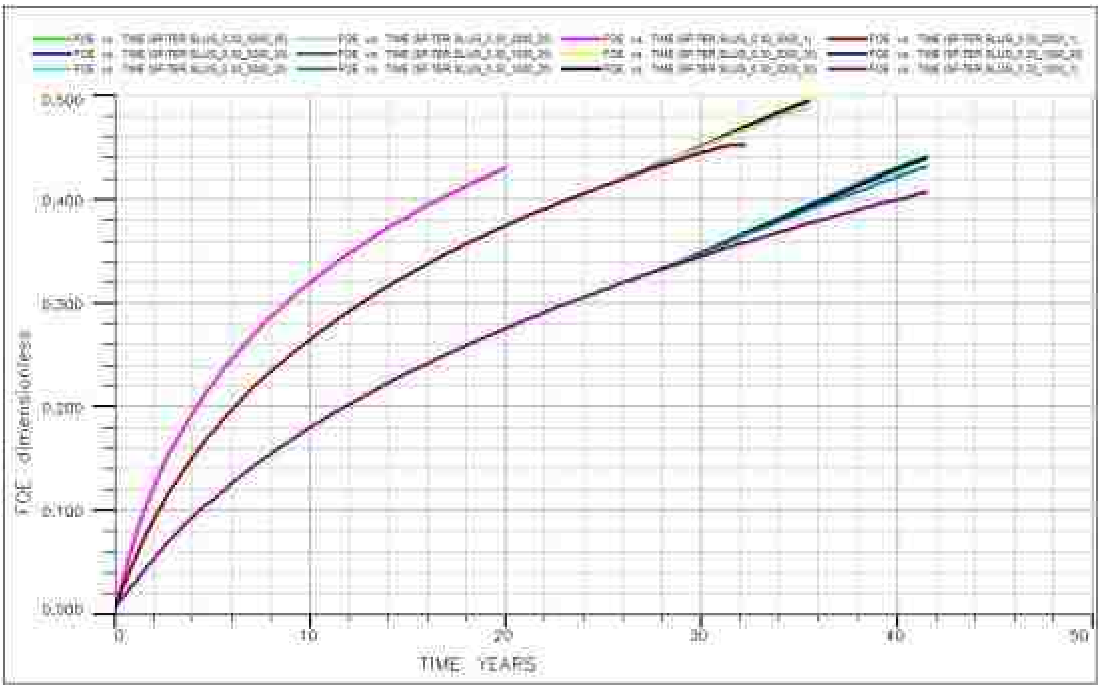

Figure 4-31: Oil recovery efficiency for different scenarios, tertiary surfactant flooding_0.3 PV

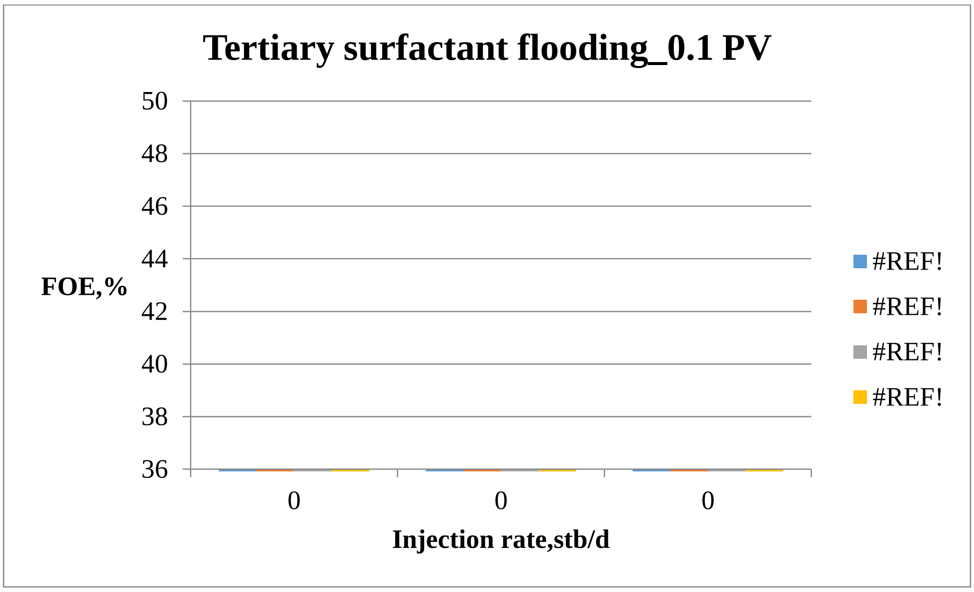

Figure 4-32: FOE vs. injection rate at different surfactant concentrations (tertiary surfactant flooding _0.1 PV)

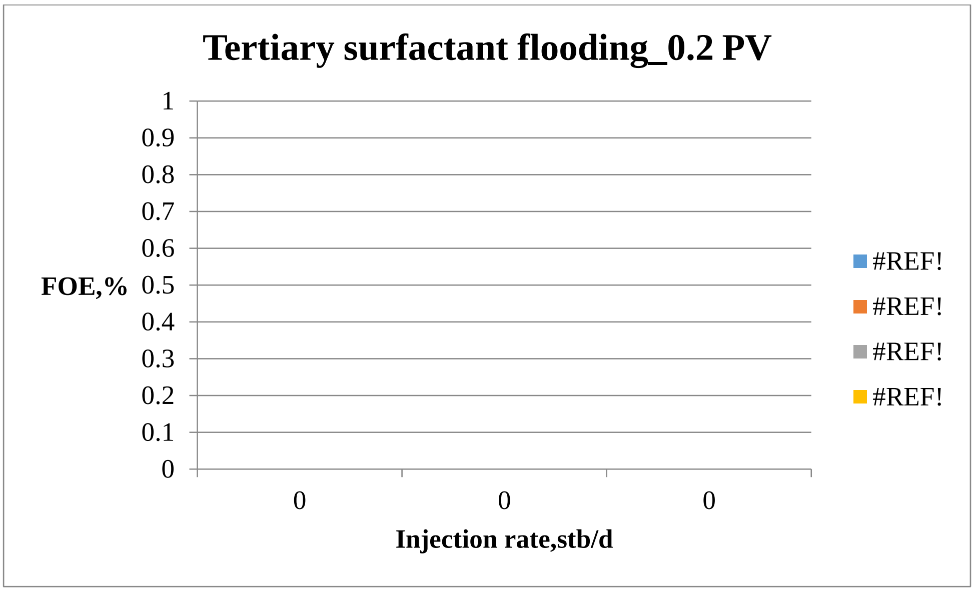

Figure 4-33: FOE vs. injection rate at different surfactant concentrations (tertiary surfactant flooding _0.2 PV)

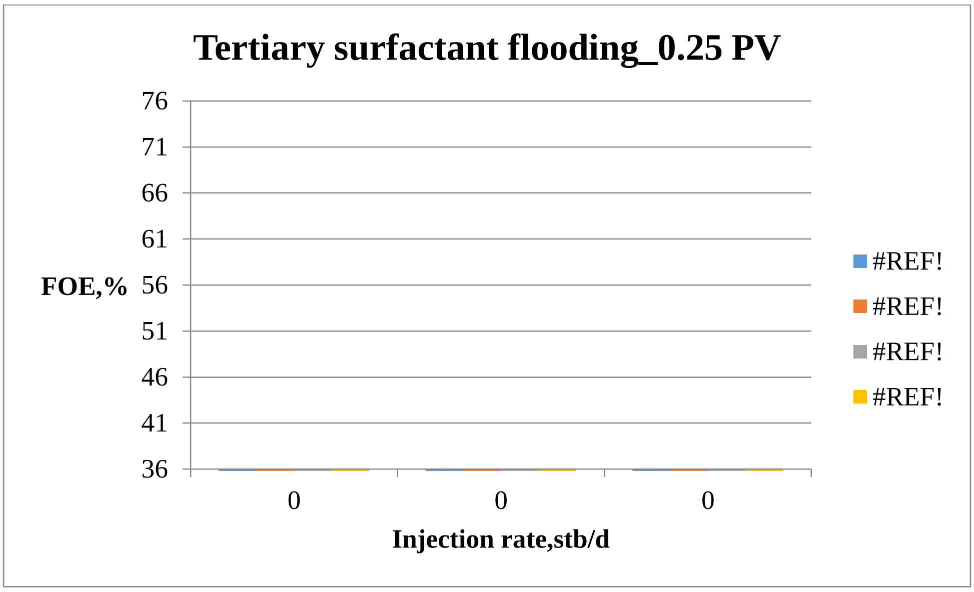

Figure 4-34: FOE vs. injection rate at different surfactant concentrations (tertiary surfactant flooding _0.25 PV)

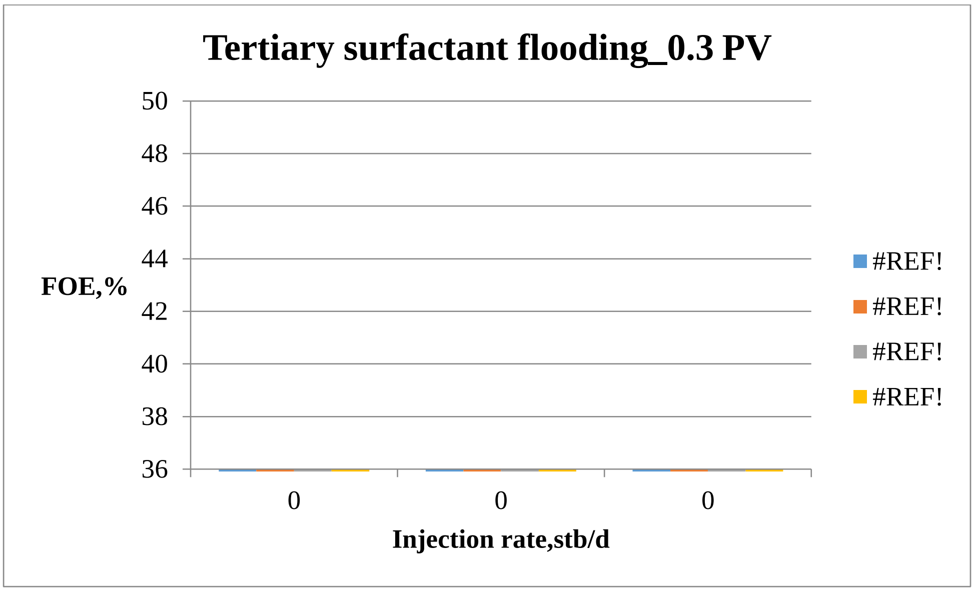

Figure 4-35: FOE vs. injection rate at different surfactant concentrations (tertiary surfactant flooding _0.3 PV)

The percentage increase in oil recovery efficiency at the smallest surfactant slug size and minimum concentration over waterflooding for the 1000, 2000 and 3000 stb/d are 0.10, 0.40 and 0.21% which are insignificant. It is clear that the surfactant slug size and concentration have a direct relationship with the oil recovery efficiency.

Increasing the injection rate from 1000 to 2000 stb/d increases the oil recovery but increasing the rate to 3000 stb/d has a negative effect.

Table 4-22: Percentage increase in FOE at 30 lb/stb (tertiary surfactant flooding)

Surfactant slug size (PV)	**FOE @ 1000 stb/d (%)**	**Percentage Increase-FOE (%)**	**FOE @ 2000 stb/d (%)**	**Percentage Increase-FOE (%)**	**FOE @ 3000 stb/d (%)**	**Percentage Increase-FOE (%)**
0.1	41.81		46.50		43.00	
0.2	43.29	3.54	47.54	2.24	43.00	0.00
0.25	43.78	1.13	48.91	2.88	43.00	0.00
0.3	43.92	0.32	49.38	0.96	43.00	0.00

Table 4-22 shows the effect of increasing the surfactant slug size and injection rate at 30 lb/stb surfactant concentration. Setting the injection rate at 1000 stb/d and increasing the surfactant slug size at this specific surfactant concentration shows that the percentage increase in the oil recovery efficiency became less significant as the slug size increased. When the injection rate was 2000 stb/d, the percentage increase in FOE was most significant when the surfactant slug size was increased from 0.2 to 0.25 PV. The oil recovery efficiency remained constant regardless of the surfactant slug size when the rate was increased to 3000 stb/d because the water cut limit was reached before the period where surfactant injection was intended to be started.

Technically, the following table presents the optimum combination of surfactant concentration and injection for the various surfactant slug sizes:

Table 4-23: Optimum combination of surfactant concentration and injection for the different surfactant slug sizes (tertiary surfactant flooding)

Surfactant slug size (PV)	Optimum surfactant concentration (lb/stb)	Optimum injection rate (stb/d)
0.1	25	2000
0.2	25	2000
0.25	25	2000
0.3	25	2000

4.2 Economic Model

Once the optimum scenarios are determined from the technical point of view, the economic model is needed to decide the feasibility of the project. The results that were obtained from reservoir simulation for the cases presented in Tables 4-9,4-16 and 4-23 were fed into the economic model as an input.

The procedure for the economic model is as follows:

- Input
  - Results of reservoir simulation calculations (identified in the previous section)
  - Economic parameters: Surfactant concentration, oil price, incremental oil production cost , water injection cost , water production cost, surfactant cost , incremental surfactant production cost , incremental surfactant injection cost.
- Output
  - Incremental cash flow
  - Net present value (NPV)

Fanchi (2006) defined the cash flow as the aggregate cash flow for each specific time and represents the impact of the project on the firm over time. The net present value The sum of all project cash flows, discounted back to a common point in time.

The range of variables that are used to assess the design, using project profitability measures as the decision making tool in the economic model of the surfactant flooding scenarios are given in Table 4-24.

Table 4-24: Ranges used for economic parameters for the surfactant flooding sensitivities

EOR technique	**Water flooding**	**Surfactant flooding**
Duration of water flooding, years	41	Shown in Figure 4-6
Duration of surfactant flooding, years	N/A	Shown in Figure 4-6
Surfactant concentration, ppm	N/A	25-30
Oil Price, $/bbl	5,10,20,40	5,10,20,40
Incremental oil production cost,$/bbl	N/A	8
Water injection cost, $/bbl	N/A	2
Water production cost,$/bbl	N/A	2
Surfactant cost,$/bbl	N/A	1.75
Incremental surfactant production cost,$/bbl	N/A	0.5
Incremental surfactant injection cost,$/bbl	N/A	0.5

The incremental oil production cost, water injection cost, surfactant cost, Incremental surfactant production and injection costs were taken from Chinenye (2010) doctorate dissertation by analogy.

Table 4-25: Net present value for the optimum combination of surfactant concentration and injection rate for the different surfactant injection scenarios at different oil prices

	Oil price ($/bbl)			
	5	**10**	**20**	**40**
Development Process	**NPV (mm$)**			
Waterflooding	0	2	5	7
Continuous surfactant injection	-3	-1	0	1
Secondary surfactant flooding_0.1 PV	-2	-1	0	2
Secondary surfactant flooding_0.3 PV	-1	1	3	4
Secondary surfactant flooding_0.5 PV	-4	-1	2	3
Secondary surfactant flooding_0.7 PV	-3	-2	1	3
Tertiary surfactant flooding_0.1 PV	-5	-2	0	3
Tertiary surfactant flooding_0.2 PV	-3	1	6	10
Tertiary surfactant flooding_0.25 PV	-2	5	9	13
Tertiary surfactant flooding_0.3 PV	-4	2	6	11

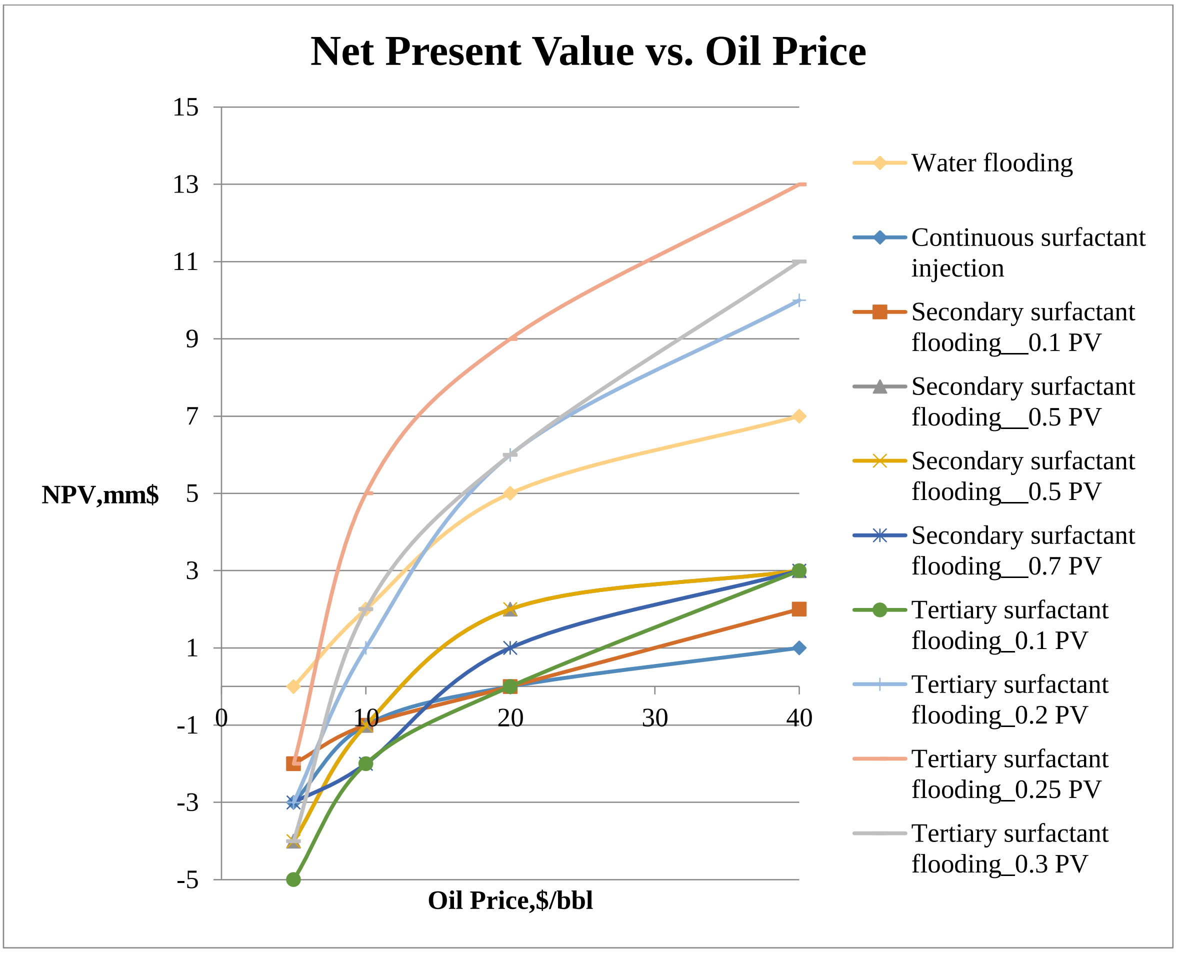

Figure 4-36: Net present value vs. Oil price for the optimum combination of surfactant concentration and injection for the different surfactant injection scenarios

The previous table and figure show the NPV at different oil prices which are 5,10,20 and 40 $/bbl for the optimum cases only. The oil price was varied in order to sense its effect on the net present value and indicate when these particular cases are considered to be profitable. At 40 $/bbl, injecting 0.5 PV of surfactant in the secondary mode while taking into consideration the optimum surfactant concentration and injection rate yields the highest net present value. The following table shows the minimum oil price below which the project is non-profitable with negative present value which were obtained from Figure 4-36 by reading the x–intercept.

Table 4-26: Minimum oil price for implementing a profitable surfactant flooding process

Development Process	**Minimum Oil price ($/bbl)**
Waterflooding	
Continuous surfactant injection	20
Secondary surfactant flooding_0.1 PV	20
Secondary surfactant flooding_0.3 PV	8
Secondary surfactant flooding_0.5 PV	13
Secondary surfactant flooding_0.7 PV	10
Tertiary surfactant flooding_0.1 PV	20
Tertiary surfactant flooding_0.2 PV	23
Tertiary surfactant flooding_0.25 PV	7
Tertiary surfactant flooding_0.3 PV	25

Chapter 5: Conclusions and Recommendations

5.1 Conclusions

Based on this study, the following can be concluded:

- Injection rate of 2000 stb/d is the optimum operating injection rate for the waterflooding.
- Implementing surfactant flooding by different processes including continuous injection, secondary recovery and tertiary recovery has increased the amount of oil recovered.
- A recovery factor of more than 50% could be achieved by continuous surfactant injection process, using 2000 stb/d as the injection rate and 30 lb/stb as the surfactant concentration.
- Continuous surfactant flooding is impractical since it requires large volumes of surfactant for injection.
- A maximum oil recovery of 52% could be achieved by injecting 0.7 PV of surfactant in the secondary mode using surfactant concentration of 35 lb/stb and 2000 stb/d as an injection rate.
- A maximum oil recovery of 50% could be achieved by injecting 0.3 PV of surfactant in the tertiary mode using 35 lb/stb of surfactant and 2000 stb/d as an injection rate.
- The optimum combination of surfactant concentration and injection rate for the secondary and tertiary recovery process varies depending on the pore volumes of surfactant injected.

- Surfactant flooding promotes incremental oil production by increasing the amount of oil produced before reaching the economic water cut limit of 90%.
- The oil price was varied in the economic analysis to sense its effect on the net present value and indicate when the optimum scenarios are considered to be profitable.
- The optimum development process from the technically and economically is injecting 0.25 PV of surfactant as a tertiary recovery process using 25 lb/stb of surfactant and 2000 stb/d as an injection rate to recover 48.91% of the initial oil in place.

5.2 Recommendations

The recommendations for future work could include:

- Studying the effect of different injection patterns on the recovery.
- Carrying out laboratory experiments to verify the simulation results.
- Perform detailed economic analysis to include all the cases attempted in the simulation.

References

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Appendix

Surfactant Flooding Model Data File (Continuous surfactant injection, 2000 stb/d, 30 lbs/stb)

```
RUNSPEC

TITLE
Synthetic model  oil/water/surfactant
DIMENS
  30   21    15  /

OIL

WATER

SURFACT

SURFACTW

FIELD

TABDIMS
   2    1   20   20    1   20 /

WELLDIMS
   2    20    1    2 /

START
  1 'JAN' 2009  /

NSTACK
 100 /


UNIFOUT


GRID
==============================================================
INIT
```

```
BOX
1 30   1   21    1   1/
TOPS
630*4000/

EQUALS
'DX'    75    1  30   1   21    1   15/
'DY'    75/
'DZ'    10/
'PERMX'  100    1 30    1   21     1   5/
'PORO'   0.2 /
'PERMX'  1000    1 30    1   21     6   10/
'PORO'   0.22 /
'PERMX'  100    1 30    1   21     11   15/
'PORO'   0.2 /
/


COPY
  PERMX PERMY   /
  PERMX PERMZ   /
  /

MULTIPLY
   PERMZ    0.1  /
/

RPTGRID
    'PORV' 'TRANX' 'TRANY' 'TRANZ' 'KOVERD'/



PROPS
==============================================================

SWOF
0.2016   0.0000   0.9656   0.2469
0.2527   0.0006   0.7221   0.1583
0.3038   0.0051   0.5264   0.0963
0.3550   0.0173   0.3697   0.0548
0.4061   0.0411   0.2477   0.0286
0.4573   0.0802   0.1560   0.0133
0.5084   0.1386   0.0903   0.0052
0.5595   0.2202   0.0462   0.0015
```

```
0.6107   0.3286   0.0195   0.0003
0.6618   0.4679   0.0058   0.0000
0.7129   0.6418   0.0007   0.0000
0.7641   0.8543   0.0000   0.0000
1.0000   1.0000   0.0000   0.0000
/
0.2016   0.0000   0.9656   0.2469
0.2527   0.0006   0.7221   0.1583
0.3038   0.0051   0.5264   0.0963
0.3550   0.0173   0.3697   0.0548
0.4061   0.0411   0.2477   0.0286
0.4573   0.0802   0.1560   0.0133
0.5084   0.1386   0.0903   0.0052
0.5595   0.2202   0.0462   0.0015
0.6107   0.3286   0.0195   0.0003
0.6618   0.4679   0.0058   0.0000
0.7129   0.6418   0.0007   0.0000
0.7641   0.8543   0.0000   0.0000
1.0000   1.0000   0.0000   0.0000
/



-- Densities in lb/ft
--          Oil     Wat     Gas
--          ---     ---     ---
DENSITY
            49      63     0.01 /


-- PVT data for dead oil
--       P        Bo       Vis
--     ----      ----     -----
PVDO
        300      1.25      1.0
        800      1.20      1.1
       6000      1.15      2.0 /




-- PVT data for water
--       P        Bw       Cw        Vis     Viscosibility
```

```
--      ----       ----      -----       -----     -------------
PVTW
        4500       1.02      3e-06       0.8          0.0 /


-- Rock compressibility
--         P           Cr
--      ----        -----
ROCK
        4500        4e-06 /


SURFVISC
 0.0     0.8
 30.     5.0  /

SURFADS
 0.0     0.0000
 1.0     0.0005
30.0     0.0005  /

 0.0     0.0000
 1.0     0.0005
30.0     0.0005  /


SURFADDW
----Concentration  Weighting of oil-wet
----of adsorbed    to water-wet
----surfactant     saturation function
---- (kg/kg)
      0             1.0
   0.0001           0.8
   0.0002           0.4
   0.0005           0.0
/
/
/



SURFST
 0.0    0.44
```

```
 1.0    8.8E-6
 30.0   8.8E-6  /

SURFCAPD
  -9    0.0
  -4.5  0.0
  -2    1.0
  10    1.0 /

  -9    0.0
  -4.5  0.0
  -2    1.0
  10    1.0 /


SURFROCK
 1  22.1 /
 2  22.1 /

RPTPROPS
    -- PROPS Reporting Options
--
'SURFVISC' 'PVDO' 'PVTO' 'STOW'
 /


--RPTREGS
-- Controls on output from regions section
--
--'MISCNUM'
--/

REGIONS
==============================================================

SATNUM
 9450*1 /

SURFNUM
 9450*2 /

SURFWNUM
 9450*2 /
```

```
RPTREGS
  /


SOLUTION
============================================================

EQUIL
4000  4000  6000  0   0   0   0   0   0  /


RPTRST
BASIC=2/

--RPTSOL
-- Initialisation Print Output
--
--'RESTART=2' 'FIP=2' 'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPPLY=2' 'PCOW' 'SURFBLK' /

SUMMARY
============================================================


-- Field average pressure

FPR
-- Bottomhole pressure of all wells

WBHP
/

-- Field Oil Production Rate
FOPR
-- Field Water Production Rate
FWPR

-- Field Oil Production Total
FOPT

-- Field Water Production Total
FWPT

-- Field Water cut

FWCT
```

-- Field Water injection total

FWIT

-- Field oil recovery efficiency

FOE
FWIR

FTPRSUR
FTPTSUR
FTIRSUR
FTITSUR
FTADSUR

BOSAT

15 11 1
15 11 2
15 11 3//
/
BWSAT

15 11 1
15 11 2
15 11 3//
/
BKRO

15 11 1
15 11 2
15 11 3//
/
BWKR

15 11 1
15 11 2
15 11 3//
/
EXCEL

SCHEDULE
==

```
--RPTSCHED
--'PRES' 'SWAT' 'RESTART=2' 'FIP=2' 'WELLS=2' 'SUMMARY=2' 'CPU=2' 'WELSPECS'
--'NEWTON=2' 'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPSALT=2' 'SURFBLK' 'SURFADS'
'FIPSURF' /

WELSPECS
'I'  'G'   8  11  4000  'WAT'  0.0  'STD'  'SHUT'  'NO'  /
'P'  'G'   22 11  4000  'OIL'  0.0  'STD'  'SHUT'  'NO'  /
/

COMPDAT
'I'   8   11   1   15 'OPEN'   0  .0   1.0 /
'P'   22  11   1   15 'OPEN'   0  .0   1.0 /
/

WCONPROD
'P' 'OPEN' 'BHP' 5* 3500.0 /
/
WECON
'P' 1* 1* 0.9 2*  WELL   YES /
/

WCONINJE
'I' 'WAT' 'OPEN' 'RATE' 2000.0 /
/

WSURFACT
 'I'  30.0 /
 /

TUNING
 1* 185 /
 /
 2*  100 /

DATES

1 APR 2009/
1 JUL 2009/
1 OCT 2009/
1 JAN 2010/
1 APR 2010/
1 JUN 2010/
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1 JUL 2010/
1 JAN 2011/
1 JAN 2012/
1 JAN 2013/
1 JAN 2014/
1 JAN 2015/
1 JAN 2016/
1 JAN 2017/
1 JAN 2018/
1 JAN 2019/
1 JAN 2020/
1 JAN 2021/
1 JAN 2022/
1 JAN 2023/
1 JAN 2024/
1 JAN 2025/
1 JAN 2026/
1 JAN 2027/
1 JAN 2028/
1 JUL 2028/
1 JAN 2029/
1 JUL 2029/
1 JAN 2030/
1 JUL 2030/
1 JAN 2031/
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1 JAN 2048/
1 JUL 2048/
1 JAN 2049/
1 JUL 2049/
1 JAN 2050/
1 JUL 2050/

/


--RPTSCHED
--'PRES' 'SWAT' 'RESTART=2' 'FIP=2' 'WELLS=2' 'SUMMARY=2' 'CPU=2'
'NEWTON=2'
--'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPSALT=2' 'SURFBLK' 'SURFADS' 'FIPSURF' 'PCOW'/


END
```